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# Transcript Exhibit(s)

**Docket #(s):** E-01933A-07-0402

E-01933A-05-0650

**Exhibit # :** AECC1-AECC3, DOD1-DOD2, IBEW1-IBEW2, Kroger1, Kroger2, Mesquite1-Mesquite3, Mesquite5, RUCO1-RUCO3.

EXHIBIT
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# BEFORE THE ARIZONA CORPORATION COMMISSION

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| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA | ) | Docket No. E-01933A-07-0402 |
| IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103 | ) | Docket No. E-01933A-05-0650 |

## Direct Testimony of Kevin C. Higgins

**on behalf of**

**Phelps Dodge Mining Company and**

**Arizonans for Electric Choice and Competition**

## Revenue Requirement

**February 29, 2008**

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# DIRECT TESTIMONY OF KEVIN C. HIGGINS

## I. Introduction

**Q. Please state your name and business address.**

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

**Q. By whom are you employed and in what capacity?**

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

**Q. On whose behalf are you testifying in this proceeding?**

A. My testimony is being sponsored by Phelps Dodge Mining Company ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona. AECC is a party to the Tucson Electric Power Company ("TEP") Settlement Agreement that was approved by the Commission, with some modification, in 1999, and which is the subject of considerable discussion in TEP's filing in this docket.

**Q. Were you personally involved in the negotiations that resulted in the TEP Settlement Agreement?**

A. Yes, I was closely involved in the negotiations on behalf of AECC. I also testified before the Commission in support of the Settlement Agreement in 1999.

**Q. Did you testify in the proceeding that addressed TEP's request to amend Decision No. 62103, Docket No. E-01933A-05-0650?**

A. Yes. I filed direct and surrebuttal testimony and was cross examined in that proceeding. Docket No.E-01933A-05-0650 provided an extensive record refuting TEP's claim that the 1999 Settlement Agreement requires Standard Offer generation rates to be set equal to the Market Generation Credit ("MGC"). By this reference, I am incorporating without change my testimony from Docket No.E-01933A-05-0650 into my testimony in this proceeding.

**Q. Please describe your professional experience and qualifications.**

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

**Q. Have you previously testified in other cases before this Commission?**

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998), the hearings on the Arizona Public Service Company ("APS") Direct Access Settlement Agreement (1999), the hearings on the TEP Direct Access Settlement Agreement (1999), the AEPCO transition charge hearings (1999), the Commission's Track A proceeding (2002), the APS adjustment mechanism proceeding (2003), the Arizona ISA proceeding (2003), the APS general rate case (2004), the Trico rate case (2005), the TEP rate review (2005), the APS emergency interim rate proceeding (2006), the APS general rate case (2006), and TEP's request to amend Decision No. 62103 (2007).

**Q. Have you testified before utility regulatory commissions in other states?**

A. Yes. I have testified in over seventy other proceedings on the subjects of electric utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board.

A more detailed description of my qualifications is contained in Attachment A, attached to this testimony.

## II. Overview and Conclusions

**Q. What is the purpose of your testimony in this phase of the proceeding?**

A. My testimony addresses several revenue requirement issues in TEP's general rate case filing, and recommends adjustments to TEP's proposed revenue requirement in support of a just and reasonable outcome.

TEP's filing contains proposed rates for three different scenarios: (1) market-based rates for generation service ("Market Methodology"); (2) cost-of-service-based rates for generation service ("Cost-of-Service Methodology"); and (3) a hybrid of cost-of-service and market-based rates ("Hybrid Methodology").

With respect to TEP's proposed Market Methodology, I provide a summary of AECC's position in Docket No. E-01933A-05-0650, which responds to TEP's claim that the 1999 Settlement Agreement entitles the Company to charge Standard Offer generation rates based on the MGC methodology effective January 1, 2009. My testimony in that docket provided an extensive response to the Company's claim. As I testified in that proceeding, TEP mischaracterizes the MGC provision in the 1999 Settlement Agreement, and the Company's claim that Standard Offer generation rates are to be set equal to the MGC is wholly incorrect. Consequently, TEP's proposed Market Methodology is without foundation and should be rejected by the Commission.

The Hybrid Methodology is offered by TEP as a middle ground between its Cost-of-Service Methodology and Market Methodology. However, as with the Market Methodology, the Hybrid Methodology proposal originates from the premise that TEP is entitled to set rates based on the MGC. As this premise is without foundation, I recommend against adoption of the Hybrid Methodology.

Because TEP's claim that it is entitled to charge Standard Offer generation rates based on the MGC was fully addressed in Docket No. E-01933A-05-0650, and because I have incorporated into this testimony by reference my previous response to that claim, I will not repeat here my full refutation of the Company's argument on this point. Instead, the primary focus of my testimony in this phase of the proceeding is to address TEP's requested revenue requirements associated with the Company's Cost-of-Service Methodology.

**Q. Please summarize your conclusions and recommendations with respect to revenue requirement issues in this proceeding.**

A. I offer the following conclusions and recommendations:

(1) The appropriate approach for setting rates after January 1, 2009 is on a cost-of-service basis. The TEP proposal that best reflects cost-of-service is its Cost-of-Service Methodology. I recommend the following adjustments to the revenue requirement requested by TEP in its Cost-of-Service Methodology proposal:

(a) TEP's proposed Termination Cost Regulatory Asset Charge ("TCRAC") is without merit and should be rejected. Elimination of this proposed charge reduces TEP's requested revenue requirement by $117.6 million.

(b) TEP's proposed fixed cost recovery rate for Springerville Unit No. 1 of $25.67 per kW-month significantly overstates the Company's test year expenses for fixed costs under its capital lease. The fixed cost recovery rate should be reduced to $18.63 per kW-month to better reflect the Company's fixed cost expense in the test year. This adjustment reduces TEP's requested revenue requirement by $30.5 million.

(c) TEP inappropriately excludes from base rates any credit to customers attributable to the margins from short-term sales. Instead of such an exclusion, 100 percent of the test year margins from short-term sales should be reflected in base rates. This adjustment reduces TEP's requested revenue requirement by $24.0 million.

(d) TEP has proposed the creation of regulatory assets to recover certain costs associated with the buyouts of coal contracts to supply the Sundt and San Juan Stations. I agree with recognizing regulatory assets for the respective buyouts, but recommend that the amortization period start at the time the buyouts occurred, 2002. At the same time, because the buyouts will provide cost avoidance over an extended period of time, the amortization periods should be extended from the four-year period proposed by TEP to a ten-year period. This adjustment reduces TEP's proposed revenue requirements by $5.5 million per year.

(e) I recommend <u>against</u> adoption of TEP's proposal to recover the fixed costs of the Luna Energy Facility through a "market-based capacity charge" of $7.00 per kW-month. If customers are going to be responsible for the recovery of Luna Energy Facility costs, then the recovery of fixed costs should be based on inclusion of the facility's net plant in service in rate base, and recovery of fixed O&M costs based on test year pro-forma expenses. My recommendation reduces TEP's proposed revenue requirements by $6.7 million per year.

These five adjustments reduce TEP's requested revenue requirement by a total of $184.2 million. By themselves, these adjustments demonstrate that TEP's current rates should be *reduced* by at least $3.5 million (using TEP's currently-filed fuel and purchased power cost forecast).

(2) I am neither recommending for nor against adoption of a Purchased Power and Fuel Adjustment Clause ("PPFAC") for TEP. In my opinion, TEP has not produced compelling quantitative evidence demonstrating its financial exposure to fuel volatility. At the same time, I am aware of the significant exposure to fuel volatility faced by the other major jurisdictional utility, APS, and acknowledge the possibility that TEP may also face material exposure in this regard. If a PPFAC is adopted, then I recommend the following modifications to the structure proposed by TEP:

(a) The Base Cost of Fuel and Purchased Power should include a credit to customers for 100 percent of the margins from short-tem sales during the test year.

(b) Rather than setting each year's fuel and purchased power recovery based on a forecast, as TEP proposes, the PPFAC should simply recover the difference between <u>actual</u> purchased power and fuel costs and the Base Cost of Fuel and Purchased Power in rates.

(c) To maintain incentives for the utility to manage its costs effectively, responsibility for changes in fuel and purchased power costs should be shared between the utility and customers. I recommend a 90/10 sharing between customers and TEP.

(d) The same 90/10 sharing percentage used for fuel and purchased power should be applied to changes in short-term sales margins (relative to the margins included in the Base Cost of Fuel and Purchased Power). That is, 90 percent of any change in short-term sales margins should accrue to customers.

(e) The PPFAC rate charged to customers should be differentiated by voltage level to properly reflect line loss differences among customers taking service at different voltage levels.

(3) If the Cost-of-Service Methodology is adopted and if a PPFAC is also adopted, then I recommend that the True-Up Revenues established in Docket No. 69658 should be applied as a credit against future PPFAC balances. These revenues should earn interest at the interest rate approved for PPFAC balances. Alternatively, if the Cost-of-Service Methodology is adopted and if a PPFAC is not adopted, then I recommend that the True-Up Revenues be returned to customers over a three-year period, and earn interest at the rate applied to TEP's regulatory asset balances. These two alternative recommendations assume that TEP's proposed TCRAC is rejected by the Commission. If, for some reason, the TCRAC is adopted in whole or in part, then the True-Up Revenues should be applied against the TCRAC balance.

Although the True-Up Revenues properly belong to customers, AECC would be willing to accept a resolution in which the True-Up Revenues were not returned to customers under the Cost-of-Service Methodology, if, and only if, this concession were accompanied by TEP's withdrawal of all claims that the Company would be harmed by setting rates at cost-of-service. Absent such action by TEP, the True-Up Revenues should be returned in full to customers.

If the Cost-of-Service Methodology is not adopted, then the True-Up Revenues should be returned to customers over a twelve-month period, and should earn interest at the same return applied to TEP's regulatory assets.

(4) TEP has offered its Cost-of-Service Methodology and Hybrid Methodology with certain direct access conditions attached, namely, that direct access rights for customers be eliminated in the former case and restricted to customers 3 MW and greater in the latter case. I recommend that the Commission reject both of those conditions. Direct access is a statewide issue. Standard offer generation service in both the APS and SRP service territories is based on cost-of-service, and customers in those territories have not been forced to relinquish their rights to direct access. If issues of direct access are to be addressed, it should occur in its own docket. Customer direct access rights should not be rolled back piecemeal as part of this proceeding.

## III. <u>Review of AECC's Response to TEP's Assertions Regarding Market Pricing of Retail Service in Docket No. E-01933A-05-0650</u>

**Q. What does TEP claim with respect to the MGC and retail prices?**

A. TEP claims that the 1999 Settlement Agreement established the rate for Standard Offer generation service at a price equal to the MGC, and that further, the Company is entitled to charge Standard Offer generation rates based on the MGC methodology effective January 1, 2009. In Docket No. E-01933A-05-0650, I provided extensive testimony demonstrating that neither of these claims is correct. Staff, RUCO, and the Department of Defense independently concurred with this conclusion.[1]

**Q. Please summarize AECC's position with respect to these claims as presented in your testimony and AECC's other filings in Docket No. E-01933A-05-0650.**

A. AECC's position may be summarized in the following nine points:

(1) The MGC was developed for the sole purpose of calculating stranded costs.

(2) There is no basis in the 1999 Settlement Agreement for setting Standard Offer generation rates equal to the MGC, either in the past, present or after January 1, 2009.

(3) The Electric Competition Rules require that Standard Offer rates be based on cost of service.

(4) The 1999 Settlement Agreement does not provide for market-based rates for Standard Offer generation service except as such rates would have resulted from implementing the divestiture requirement in Section 3.1 of the Agreement.

(5) Had TEP's generation assets been divested as initially required in the Electric Competition Rules and as required in the 1999 Settlement Agreement, then jurisdiction over these assets would have been transferred to FERC, and output from these units would have been sold exclusively in wholesale markets, most likely at FERC-approved market rates. Under such a scenario, cost-based Standard Offer rates would necessarily reflect the pass-through of market prices

[1] See discussion in Decision No. 69568, paragraph 62 [p. 12, lines 7-20].

upon expiration of the rate cap on December 31, 2008, subject to approval in a general rate case. (In this sense, AECC agrees with TEP that there was an expectation in 1999 that Standard Offer generation rates were to be reflective of market prices after December 31, 2008.)

(6) The Commission's Track A Decision, issued September 10, 2002, directed TEP to cancel its plans for the divestiture of its assets, nullifying the divestiture provision in the Settlement Agreement.

(7) The Commission's action cancelling the divestiture of TEP's generation assets eliminated the means through which TEP's Standard Offer generation rates would have been based on market prices.

(8) TEP did not appeal the Track A decision, which I am informed by counsel is now res judicata, collaterally estopping TEP from arguing that the Decision improperly altered the Settlement Agreement.

(9) In the absence of divestiture, the cost-of-service requirements for Standard Offer service apply to the costs of TEP's un-divested generation assets.

**Q. In point Number 5 above, you stated that AECC agrees with TEP that there was an expectation in 1999 that Standard Offer generation rates were to be reflective of market prices after December 31, 2008. At what point does your position and that of TEP's diverge?**

A. It is AECC's position that divestiture of generation assets would have caused TEP's Standard Offer generation rates to be reflective of market prices after December 31, 2008. In contrast, TEP maintains that Standard Offer generation rates after December 31, 2008 are required to be reflective of market prices because the 1999 Settlement Agreement sets these rates equal to the MGC. As I stated above, AECC strongly maintains that this claim is untrue, as the Settlement Agreement contains no such provision.

**Q. Given these conclusions, what is your recommendation to the Commission regarding TEP's Market Methodology proposal?**

A. The premise behind the Market Methodology proposal is that the 1999 Settlement Agreement provides that the rates for Standard Offer generation service are to be set equal to the MGC. That claim is incorrect. Further, the means through which market prices were to be passed through to customers after December 31, 2008 was eliminated when the Track A Decision nullified the divestiture requirement in the Settlement Agreement. Consequently, TEP's proposed Market Methodology is without foundation and should be rejected.

**Q. What is your recommendation regarding TEP's Hybrid Methodology proposal?**

A. The Hybrid Methodology is offered by TEP as a middle ground between its Cost-of-Service Methodology and Market Methodology. However, as with the Market Methodology, the Hybrid Methodology proposal originates from the premise that TEP is entitled to set rates based on the MGC. As this premise is without foundation, I recommend against adoption of the Hybrid Methodology. I address TEP's Hybrid Methodology proposal further in Section VII of this testimony.

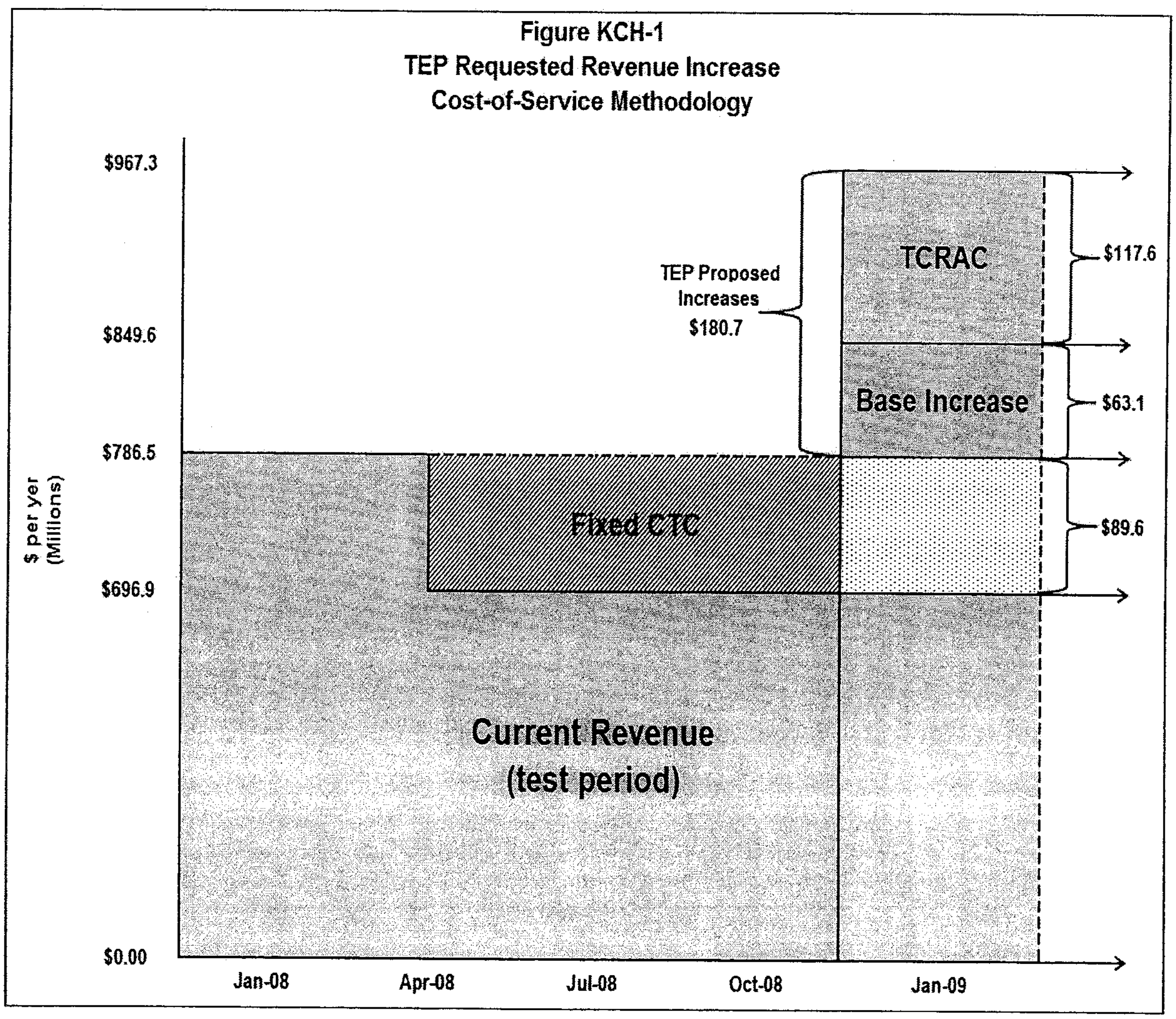
## IV. <u>TEP revenue requirements – Cost-of-Service Methodology</u>

**Q. What increase in revenue requirement has TEP requested under its Cost-of-Service Methodology scenario?**

A. TEP is requesting an increase in revenue requirement of $180.7 million over current rates, or 23 percent, under its Cost-of-Service Methodology scenario. (In using the term "current rates" I am referring to rates that include the Fixed

CTC component.) This increase is based upon TEP's currently-projected fuel and purchased power price forecast. TEP has stated that it intends to update this forecast (and presumably its requested revenue requirement) during the course of the proceeding.

TEP's requested rate increase is reproduced in Schedule KCH-1, page 1, and is graphically depicted in Figure KCH-1, below.



As shown, of the $180.7 million increase proposed by TEP, $117.6 million is comprised of the proposed Termination Cost Regulatory Asset Charge and $63.1 million represents an increase in base rates.

Pursuant to the terms of the 1999 Settlement Agreement, the Fixed CTC is supposed to be terminated on December 31, 2008, or after it yields stranded cost recovery of $450 million, whichever comes first. My understanding is that recovery of the $450 million will be achieved around May, 2008. In Decision No. 69568, the Commission determined that in the interest of rate stability, TEP's Standard Offer rates should remain unchanged pending the outcome of this rate case; thus, rates will not be reduced by the amount of the Fixed CTC in May 2008 as originally envisaged. However, the Decision also provided that TEP customers should be protected by providing for a mechanism to refund or credit the revenues, plus interest, that will continue to be collected by the modified treatment of the Fixed CTC, until new rates are approved. These revenues are called True-Up Revenues.

On an annualized basis, the Fixed CTC collects approximately $89.6 million. Therefore, if base rates are viewed as <u>excluding</u> the Fixed CTC component, then the increase in revenue requirement being requested by TEP should be viewed as equal to $270.3 million, i.e., $180.7 million plus retention of the $89.6 million in Fixed CTC revenues.

**Q. What adjustments are you recommending with respect to TEP's requested revenue requirements?**

A. My recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular revenue issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue. I am recommending the following adjustments to the revenue requirement proposed by TEP:

(1) Removal of TEP's proposed Termination Cost Regulatory Asset Charge [$117.6 million];

(2) A reduction in TEP's proposed fixed cost recovery rate for Springerville Unit No. 1 to reflect the Company's fixed cost expense in the test year [$30.5 million];

(3) Inclusion in base rates of 100 percent of off-system sales margins from short-term sales [$24.0 million];

(4) Recognition of regulatory assets for the buyouts of the coal supply contracts for the Sundt and San Juan Stations, but initiating the amortization period at the time the buyouts occurred (2002) and extending the length of the amortization periods from the four-year period proposed by TEP to a ten-year period [$5.5 million]; and

(5) Elimination of TEP's proposed "market-based capacity charge" of $7.00 per kW-month for the Luna Energy Facility, and instead recovering fixed costs through inclusion of the facility's net plant in service in rate base and recovery of its fixed O&M costs based on test year pro-forma expenses [$6.7 million].

The impact of these five adjustments is shown in Schedule KCH-1, page 2. The cumulative impact of these adjustments reduces TEP's requested revenue requirement by a total of $184.2 million (as shown in line 13 of Schedule KCH-1, page 2). These adjustments demonstrate that TEP's current rates should be *reduced* by at least $3.5 million (using TEP's currently-filed fuel and purchased power cost forecast).

### A. Termination Cost Regulatory Asset Charge ("TCRAC")

**Q. What is TEP's proposal for a Termination Cost Regulatory Asset Charge ("TCRAC")?**

A. As explained in the direct testimony of Kentton C. Grant, TEP has proposed that it be awarded a regulatory asset in the amount of $788 million if the Cost-of-Service Methodology is adopted. Mr. Grant asserts that such a regulatory asset is necessary "in recognition of the economic burden imposed on TEP as a result of the extended rate freeze and return to full cost-of-service regulation."[2] The mechanism TEP proposes for recovering this proposed regulatory asset (plus interest) is the TCRAC, which would be levied for ten years. The first year cost to TEP customers of the TCRAC would be $117.6 million.

**Q. What is your assessment of this proposal?**

A. The TCRAC proposal is without merit and should be rejected. TEP's claim that it has incurred an economic burden that warrants redress is grounded in its contention that the 1999 Settlement Agreement set rates equal to the MGC. According to TEP's argument, setting post-2008 Standard Offer generation rates based on cost-of-service deprives the Company of this alleged benefit in the Settlement Agreement. But as I stated above, the MGC issue was thoroughly

[2] Direct testimony of Kentton C. Grant, p. 2, lines 22-25.

addressed in Docket No. E-01933A-05-0650, and the record in that case demonstrates that TEP's claim that generation rates were to be set equal to the MGC is simply untrue.

That said, I agree that a significant change was made with respect to the parameters governing the pricing of Standard Offer generation during the 1999-2008 transition period. That change was the Track A Decision, which nullified the divestiture requirements of the Electric Competition Rules, the APS Settlement Agreement, and the TEP Settlement Agreement. In cancelling the divestiture of TEP's generation assets, the Track A Decision eliminated the means through which TEP retail customers would be charged market prices for Standard Offer service. APS clearly recognized these implications and appealed the Track A Decision, citing among other things, APS's reliance on the divestiture provision of its Settlement Agreement and the adverse impact to APS and its affiliates from the cancellation of divestiture.[3] When APS filed its first rate case after the Track A Decision, it filed to recover Standard Offer generation costs on a cost-of-service basis.

Unlike APS, TEP did not appeal the Track A Decision. If anything, TEP encouraged the Commission to delay, if not, cancel divestiture of its generation assets. It is unfathomable to me that TEP did not recognize the implications for its future Standard Offer generation rates resulting from the cancellation of its asset divestiture as required by the Track A Decision.

**Q. Did TEP have a financial interest in delaying or cancelling divestiture?**

A. Apparently, yes. According to the testimony of TEP witness James S. Pignatelli in Docket No. E-01933A-05-0650, divestiture would have subjected TEP to higher federal income taxes as it would have led to a violation of the provisions of the Company's two-county financing, which conveys special tax benefits to the Company.[4] As TEP was (and is) operating under a retail rate cap, the increased income tax expense that would have resulted from divestiture would have been absorbed by TEP shareholders. Thus, TEP benefitted from the cancellation of divestiture and the nullification of the divestiture requirement in the Settlement Agreement. However, while TEP accepted the benefits conveyed to it by the Track A Decision, the Company is now unwilling to accept the full consequences of that Decision, namely the implications for Standard Offer generation rates. Rather than admit that the cause of the change in the basis for setting Standard Offer generation rates is the Track A Decision, which I am informed by counsel is res judicata, TEP points to non-existent provisions in the 1999 Settlement Agreement concerning the MGC, and claims that failure to honor said provisions will cause the Company harm.

**Q. Are there other aspects of the 1999 Settlement Agreement that have bearing on this discussion?**

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[3] *Arizona Public Service Company v Arizona Corporation Commission*, Superior Court of the State of Arizona, Docket No. CV-2002-022232, Complaint filed November 15, 2002. See especially paragraphs 21and 27-29. APS's Complaint was later withdrawn following resolution of a subsequent rate case.

[4] "...[O]ne of the reasons that we actually requested the Track A, that there be some relief from mandatory divestiture, is we came very quickly to the conclusion that mandatory divestiture would put at risk our tax-exempt financing on some of our distribution and transmission facilities, which would have driven up rates...So we went in and really asked that that not be required, that it be permissive and that it be selective." Docket No. E-01933A-05-0650, Tr. at 580. Although Mr. Pignatelli states that rates would have been driven up from loss of the tax benefit, at the time of the Track A hearing, TEP had another seven years remaining on its rate cap.

A. Yes. Section 3.1 of the Settlement Agreement provides that the divestiture of TEP's assets would occur at market value. Further, Decision No. 62103, which conditionally approved the Settlement Agreement, stated that the Commission reserved the right to review the appropriate market price for the assets. As the divestiture never took place, TEP is now attempting to realize market pricing without ever having transferred the assets to an entity required to purchase them at market value.

**Q. On page 3 of his direct testimony, Mr. Grant states that the rate freeze under the Settlement Agreement was agreed upon as part of a transition to market-based rates for generation services. Do you wish to comment on this statement?**

A. Yes. This statement gives the impression that the rate cap was tied to a transition to market rates, as if the two provisions were directly exchanged in a quid-pro-quo. Such is not the case. While any settlement agreement is most properly viewed as a "package deal," the rate cap in the Settlement Agreement was tied most prominently to the recovery of stranded cost. Indeed, the length of the rate cap was established for exactly the same length of time that TEP was permitted to recover stranded cost.

TEP's stranded cost was projected to be very large ($683 million) given the size of the Company and the Settlement Agreement provided a significant benefit to TEP by resolving the stranded cost issue in a way that protected the Company's financial health. The importance of stranded cost recovery to establishing the balance of the bargain in the TEP Settlement Agreement is demonstrated in Paragraph 13.1 of the Agreement, which is the first paragraph in a section entitled, "Contingencies to This Settlement Agreement":

> 13.1 Neither the Parties nor the Commission shall take any action that would diminish the recovery of TEP's stranded costs or regulatory assets provided for herein. In entering into this Settlement Agreement, TEP has relied upon the Commission's irrevocable promise to permit recovery of TEP's stranded costs and regulatory assets provided herein. Such irrevocable promise by the Commission shall be evidenced by the issuance of the Commission's Approval Order, shall survive the expiration of the Settlement Agreement and shall be specifically enforceable against this and any future Commission.

In contrast, there is no analogous language in the Settlement Agreement assuring future "market pricing" of Standard Offer generation rates, indeed no reference to market pricing of Standard Offer generation rates at all, except as implied through the Agreement's divestiture provision.

**Q. On pages 5-6 of his direct testimony, Mr. Grant calculates the amount of TEP's proposed TCRAC based on the annual retail revenue deficiency claimed by TEP in the 2004 rate review docket. Do you wish to comment on this calculation?**

A. Yes. TEP is claiming that it has suffered revenue deficiencies stemming from its adherence to the rate cap. Mr. Grant calculates the Company's cumulative deficiency claim based on the $111 million revenue deficiency filed by the Company for 2003 as part of its 2004 rate review, with additional deficiencies attributed to each subsequent year, plus carrying costs.

The $111 million revenue deficiency claimed by the Company for 2003 was not endorsed by any other party and was not approved by the Commission. The Commission merely determined that it did not have cause to *reduce* TEP's rates. As pointed out in my testimony in the 2004 rate review, TEP's calculation of a $111 million revenue deficiency relied upon an inflated fixed cost factor for Springerville Unit No. 1; failed to recognize any customer benefits from short-term wholesale sales; applied a return-on-equity that exceeded the Company's last allowed return; and employed a hypothetical capital structure that increased the equity ratio from the previously-approved hypothetical capital structure. As shown in my testimony in that docket, correction of just these four items reduced the calculated revenue deficiency from $111 million to $38 million.

Moreover, Mr. Grant calculates the "harm" to TEP starting in 2003, based on the Company's claimed revenue deficiency for the 2003 test period. However, even if the Commission were to accept TEP's claim that it is entitled to recover foregone deficiencies, the earliest time any 2003 test year deficiency would likely have been recoverable in rates would have been 2006. The Company's filing to conduct the 2004 rate review was not completed until September 15, 2004, and the direct testimony of Staff, RUCO and intervenors was not filed until June 24, 2005. Had TEP's filing for test year 2003 been the basis for a rate case it is difficult to imagine new rates taking effect before 2006. Thus, Mr. Grant overstates his cumulative deficiency claim by starting to accrue it at least three years too soon.

Finally, TEP's claim of harm ignores the realities of the very profitable years the Company experienced throughout much of the rate cap period. Based on my review of information in the 10-K filings made by TEP and/or its parent company, Unisource Energy Corporation, I have calculated that TEP has earned the following returns on common equity since 1999:

| | |
|---|---|
| 1999 | 27.20% |
| 2000 | 17.31% |
| 2001 | 24.12% |
| 2002 | 15.65% |
| 2003 | 31.75% |
| 2004 | 11.13% |
| 2005 | 8.64% |
| 2006 | 12.03% |

Clearly, over the rate cap period as a whole, TEP has done very well. While the California energy crisis was thwarting the advance of Arizona's direct access implementation, TEP was profiting handsomely selling its excess generation into wholesale markets.[5] So while it is true that TEP has lived up to its rate cap commitments, so have customers. TEP was not asked to share the profits it earned from off-system sales by lowering its retail rates.

Q. **What is the revenue requirement impact of removing the TCRAC from the Cost-of-Service Methodology results?**

A. Removing the TCRAC reduces TEP's proposed revenue requirement by $117.6 million. This is reflected by removing the TCRAC amounts shown on Schedule KCH-1, page 1, line 11.

**B. <u>Springerville Unit No. 1 Fixed Costs</u>**

Q. **What has TEP proposed with respect to the treatment of fixed costs at the Springerville Unit No. 1 generation facility?**

A. As discussed in the direct testimony of David Hutchens, TEP is proposing to significantly increase the "fixed cost recovery rate" applied to its Springerville Unit No. 1 fixed costs.

**Q. What is the fixed cost recovery rate?**

A. The fixed cost recovery rate is a unit cost that is applied to the Company's fixed costs at the Springerville Unit No. 1 for revenue requirement purposes. Unlike traditional recovery of utility plant costs, which is achieved by earning a return on net book value of plant assets, Springerville Unit No. 1 is structured as a capital lease, the fixed costs of which are an expense.

The fixed cost recovery for Springerville Unit No. 1 has been governed by Commission Decision No. 56659, issued in 1989, which involves the finding of imprudence on the part of TEP management. According to that Decision, TEP came before the Commission in 1983 and requested to transfer Springerville Unit No. 1 to a newly formed subsidiary, Alamito Company ("Alamito"). The stated purpose of the transfer was to "separate TEP's wholesale and retail businesses," although the Commission later concluded that TEP had other motives as well.[6] The Decision states that the agreement between TEP and Alamito provided for the sale and leaseback of Springerville Unit No. 1 at a price that exceeded the depreciated original cost by $220 million, and that as a result, TEP was "paying lease payments which incorporate the inflated cost of Springerville Unit No. 1."[7] The Commission ultimately concluded that TEP acted imprudently in executing

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[5] The Form 10-K filed by TEP for 2002 indicates that the average unit price for TEP's wholesale sales tripled between 1999 and 2001 and the Company's revenues from wholesale sales grew from $171 million to $734 million.

[6] Decision No. 56659, p. 7, lines 7-15 and lines 22-27.

the Springerville Unit No. 1 lease with Alamito. Among other things, the Commission determined:

"If the spin-off had been the result of an arms length transaction, free of self-dealing, we might have accepted it. However, that was not the case. In essence, TEP continued to have all the operating risk associated with Springerville Unit No. 1 and San Juan Unit No. 3 while Alamito enjoyed all the upside potential of selling the two plants at a gain. It was clearly an imprudent business decision to spin-off Alamito without amending the twelve-year Power Sale Agreement. In order to make ratepayers whole for this imprudence, the capacity purchased from Alamito should be priced at a level that prudent management could have obtained." [Emphasis in original.][8]

Consistent with this determination, the Commission ordered a fixed cost recovery rate for Springerville Unit No. 1 of $15 per kW-month, based on Staff testimony that this represented a reasonable purchase price for the capacity.

**Q. Does the Decision No. 56659 indicate that the Commission was adopting a policy of recovering Springerville Unit No. 1 fixed costs at "market" rates as a matter of philosophy?**

A. No. The Decision does not even mention the word "market" in reaching its determination regarding the recovery of Springerville Unit No. 1 fixed costs. The Commission stated that it was attempting to make ratepayers whole for the imprudent business decision of management. To do so, it needed an appropriate benchmark for establishing Springerville Unit No. 1 fixed costs.

**Q. What is the current cost of the lease payment for Springerville Unit No. 1?**

A. According to the Company's workpapers, TEP's annual capital lease obligation for Springerville Unit No. 1 for 2006 is $61.9 million. For 380

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[7] Ibid., p. 9, line 20 – p. 10, line 1.
[8] Ibid., p. 11, lines 1-11.

megawatts of capacity, this translates into a lease obligation of $13.57 per kW-month.

In addition, according to TEP's workpapers, the sum of the capital lease, O&M, and administrative and general costs for Springerville Unit No. 1 is $85 million in the 2006 test year. This yields fixed cost recovery rate of $18.63 per kW-month for the test year.[9]

**Q. What new fixed cost recovery rate has Mr. Hutchens proposed?**

A. Mr. Hutchens has proposed a fixed cost recovery rate of $25.67 per-kW-month, which is a 71 percent increase over the current fixed cost recovery rate of $15 per kW-month, and 38 percent greater than the fixed cost recovery rate for Springerville Unit No. 1 in the test year.

**Q. What is the basis of Mr. Hutchens' recommendation?**

A. Mr. Hutchens asserts that because the initial fixed cost factor of $15 per kW-month was based on the market value of capacity at the time of Decision No. 56659, the fixed cost recovery rate should be adjusted to reflect purportedly higher market values for long-term capacity at this time. Mr. Hutchens proposes to impute a price for capacity based on the difference between the hypothetical wholesale market revenues that Springerville Unit No. 1 could have received by selling its output into the wholesale market and its variable production costs. In essence, TEP is proposing that it be rewarded by having customers pay it for Springerville Unit No. 1 based on a seller's ability to mark up the price of power from the facility over its variable cost of production.

[9] TEP workpaper (0402)002628.

**Q. What is your assessment of this proposal?**

A. I recommend that the Company's proposal be rejected. It is critical to bear in mind several points here:

(1) The current fixed cost recovery rate of $15 per kW-month was determined in connection with the Commission's finding of <u>imprudence</u> on TEP's part. The Commission's use of an alternative value for capacity, in lieu of cost, was not a reward to the Company, but a penalty exacted for poor judgment on management's part. <u>That decision established a cost recovery factor based on a proxy for purchased capacity, not a market-based system of recovering costs.</u> Increasing the fixed cost recovery factor today by 71 percent, based on an assertion of higher market prices for capacity, misapplies the principle adopted in 1989, and would represent an undue reward for the Company's imprudence in the 1980s.

(2) In utility ratemaking, a portion of the fixed plant costs associated with a given generation unit generally *decline* over time, as the unit is depreciated. Springerville Unit No. 1 unit is over 20 years old, and but for TEP's choice of financing arrangement, its fixed costs would reflect significant depreciation under traditional ratemaking practice. In light of this fact, a request to increase fixed cost recovery by 71 percent as proposed by Mr. Hutchens is unreasonable.

(3) The proposed fixed cost recovery rate of $25.67 per kW-month is well in excess of the fixed cost recovery rate for Springerville Unit No. 1 of $18.63 per kW-month for the test year. Given that the Springerville Unit No. 1 lease cost was found to be imprudent by the Commission in 1989, the test year fixed cost

associated with operating under the current lease arrangement should represent the maximum level of fixed cost charged to ratepayers in this proceeding. The Commission should certainly not adopt a fixed cost recovery rate in excess of TEP's test year expense, as that would perversely reward TEP management for its past decisions that were found to be imprudent.

**Q. What do you recommend as an alternative to TEP's proposal?**

A. I recommend that Springerville Unit No. 1 fixed costs be based on the fixed cost recovery rate of $18.63 per kW-month incurred by TEP in the test year. While it could reasonably be argued that the $15 per kW-month fixed cost recovery rate established in Decision No. 56659 should be retained, I would support allowing TEP to recover its test year fixed cost recovery rate for this facility.

**Q. What are the revenue implications of accepting your recommendation?**

A. My recommendation reduces TEP's proposed revenue requirements by $30.5 million per year, as shown in Schedule KCH-2.

## C. Margins from Short Term Sales

**Q. What has TEP proposed with respect to the treatment of off-system sales margins from short-term sales?**

A. As explained in the direct testimony of Mr. Hutchens, TEP is proposing to remove all margins from short-term off-system sales in base rates. Instead, TEP is proposing that part of the benefit from short-term sales be passed on to customers through the Company's proposed purchased power and fuel adjustment clause

("PPFAC"). The sharing mechanism proposed by TEP for short-term sales is highly unusual in that customers would receive 90 percent of the off-system sales revenues in the PPFAC, but would be responsible for 100 percent of the fuel costs necessary to make such sales.

**Q. What is your assessment of TEP's proposed treatment of the benefits from short-term sales?**

A. The Company's proposed approach is unreasonable and should be rejected. There are two distinct aspects of this issue that must be addressed: (1) the Company's removal of short-term sales margins from the determination of base rates; and (2) the application of short-term sales margins to the proposed PPFAC.

**Q. Please elaborate on the first aspect you wish to address, TEP's removal of short-term sales margins from base rates.**

A. TEP reports $77.7 million in short-term sales revenue in the test year. The fuel and purchased power costs needed to support these sales is $52.4 million, producing short-term sales margins of $25.3 million. In preparing its rate filing, TEP has removed all short-term sales revenues and costs (and thus, margins) from the determination of the revenue requirement. Instead, all short-term sales revenues are proposed to be treated prospectively pursuant to the Company's proposed PPFAC.

In my opinion, this proposed treatment is entirely unjustified. The short-term sales in question are made with assets that are included in rate base, the full cost of which is allocated to customers. Consequently, the full value of the test-year benefit of these sales should be reflected as a credit to customers against base rates. This means that if the Commission accepts TEP's proposal to set the Base Cost of Fuel and Purchased Power based on a 2009 forecast, then this Base Cost of Fuel and Purchased Power should reflect a credit to customers equal to 100 percent of the margin from short-term sales for the test-year. Failure to credit customers with 100 percent of the test year margin will simply create a "hidden" supplement to the Company's ROE approved in this proceeding.

**Q. Please explain this last point.**

A. The fundamental objective of a rate case is to set rates that provide the utility an opportunity to earn its allowed rate of return. Short-term sales margins are net revenues to the utility; consequently, they have a direct impact on the utility's return. When we refer to "crediting" customers with short-term sales margins when setting base rates, we are simply <u>recognizing</u> that these net revenues contribute to the utility's net income. By recognizing these net revenues in the determination of the rates needed to reach the targeted rate-of-return, there is a dollar-for-dollar reduction in the revenues necessary to collect from customers in order to reach that return, giving rise to the notion of a revenue "credit" to customers.

Once rates are set, utilities have the incentive to maximize their short-term sales margins, as these margins flow to their respective bottom lines, enhancing their returns. In the case at hand, TEP has proposed that 10 percent of short-term revenues be retained by the Company in its PPFAC. If the test year margin from short-term sales is not fully credited to customers when base rates are set, then this margin will be excluded from the revenues that are recognized in producing the targeted rate of return. Then, to the extent that any short-term sales margins are actually realized, the revenues retained by the Company will produce a supplement to the allowed rate-of-return. Put yet another way, TEP's attempt to exclude all short-term sales margins from base rates, combined with its proposal to credit 10 percent of the short-term sales revenues to shareholders, is simply a thinly-veiled request for a higher return on equity than the 10.75 percent recommended by TEP witness Samuel C. Hadaway. In my opinion, this approach results in an unjustified transfer payment from customers to shareholders.

**Q. How do you respond to the claim that sharing revenues with the Company provides an incentive to make profitable short-term sales?**

A I will address TEP's proposal for shareholders to retain 10 percent of short-term sales revenues in the PPFAC in Section V of my testimony. At this juncture, I will make the preliminary comment that sharing short-term revenues without also sharing the costs of making these sales is entirely inappropriate. I agree, however, that sharing short-term sales margins with the Company can provide an appropriate incentive to make increased short-term sales above the level expected for the test year. But this argument has no relevance for the treatment of short-term sales margins in the establishment of base rates. If test year margins are fully credited to customers in base rates, any failure by the Company to achieve this margin will impact its bottom line. Consequently, removing test year margins from base rates provides absolutely no additional incentive for the utility to make short-term sales; as I stated, failure to credit customers with 100 percent of the short-term margins would provide nothing except a supplement to the Company's allowed ROE.

**Q. What are the revenue implications of accepting your recommendation to credit 100 percent of short-term sales margins against base rates?**

A. My recommendation reduces TEP's proposed revenue requirements by $24.0 million per year, as shown in Schedule KCH-3.

### D. Sundt and San Juan Coal Contract Buyouts

**Q. What has TEP proposed with respect to the recovery of costs associated with coal contract buyouts?**

A. As explained by Mr. Hutchens, in 2002, TEP terminated a long-term contract for coal supplied to its Sundt Station. The Company paid $11.25 million to buy out the agreement.[10]

In addition, Mr. Hutchens explains that in December 2002, in connection with the negotiation of a new underground coal supply agreement, TEP paid San Juan Coal Company $15.4 million in compensation for stranded surface operations that were no longer needed to supply coal to the San Juan Station.[11]

Mr. Hutchens testifies that each of these buyouts was less expensive than the alternatives that were available to the Company, given the contracts that were in place.

TEP is proposing that the cost of each of these buyouts be recognized as a regulatory asset in rate base and that these costs be recovered from ratepayers.

[10] Direct testimony of David G. Hutchens, p.26, line 22 - p.27, line 2.
[11] Ibid., p. 27, line 18 - p. 28, line 8.

The regulatory assets would be amortized over four years starting in the rate effective period, and would earn a return.

**Q. What is your assessment of TEP's proposed treatment of the Sundt and San Juan coal buyouts?**

A. Both buyouts appear to be prudent, but there are serious questions with respect to timing. Both buyouts occurred well before the test year, and each is a non-recurring expense. As such, there is a strong presumption <u>against</u> inclusion of recovery of such costs in rates going forward. Moreover, I am not aware of any deferred accounting order that recognizes these costs as deferred expenses.

On the other hand, both buyouts appear to result in cost avoidance going forward, which will provide a future benefit to customers. At the same time, TEP has benefited directly from the cost avoidance attributable to the buyouts since the time they were consummated in 2002.

In my opinion, the most reasonable approach to balance the interests of TEP and customers in this situation is to recognize regulatory assets for the respective buyouts, but to initiate the amortization periods at the time the buyouts occurred, 2002. This is appropriate as TEP shareholders have benefited since 2002 from the avoided costs attributable to the buyouts. At the same time, because the buyouts will provide cost avoidance over an extended period of time, the amortization periods should be extended from the four year period proposed by TEP to a ten-year period. TEP should be allowed to earn a return on the regulatory assets, but only on the regulatory asset balance remaining at the end of the test year, i.e., after recognizing amortization starting in 2002.

**Q. What are the revenue implications of accepting your recommendation with respect to the treatment of the Sundt and San Juan coal buyouts?**

A. My recommendation reduces TEP's proposed revenue requirements by $5.5 million per year, as shown in Schedule KCH-4.

**E. <u>Luna Energy Facility</u>**

**Q. What has TEP proposed with respect to the treatment of costs for the Luna Energy Facility in its Cost-of-Service Methodology proposal?**

A. The 570-MW Luna Energy Facility is located near Deming, New Mexico, and was purchased from Duke Energy by TEP and two other parties in November 2004. According to announcements in the trade press at the time, the plant was purchased for a reported $40 million, and was 48% complete at the time of purchase. Reportedly, an additional $110 million was needed to complete construction. The facility came on line April 4, 2006.

TEP's ownership share of the facility is 190 MW. According to TEP's Cost-of-Service Methodology proposal, the Company is proposing to recover the fixed costs of this facility through a "market-based capacity charge." TEP proposes this approach in lieu of seeking to earn a return on the net book value of the plant and to recover test year fixed O&M costs. Consequently, TEP has removed the Luna Energy Facility from net plant in service for ratemaking purposes, and substituted a $7.00 per kW-month capacity charge. My analysis in Schedule KCH-5 shows that TEP's proposed approach is more expensive for customers than traditional cost-based recovery.

**Q. What is your assessment of this proposal?**

A. I recommend against adoption of the Company's proposed treatment of Luna-related fixed costs. TEP is seeking to obligate customers to purchase the capacity and energy of this plant, but is seeking to price the capacity at an estimated market value rather than the actual cost to TEP of the investment and its operating expenses. I do not believe such an approach is consistent with a cost-of-service methodology.

**Q. What alternative ratemaking treatment do you recommend for the Luna Energy Facility?**

A. If customers are going to be responsible for the recovery of Luna Energy Facility costs, then the recovery of fixed costs should be based on inclusion of the facility's net plant in service in rate base, and recovery of fixed O&M costs based on test year pro-forma expenses.

**Q. What are the revenue implications of accepting your recommendation with respect to the fixed cost recovery of the Luna Energy Facility based on its net book value and test year pro-forma expenses?**

A. My recommendation reduces TEP's proposed revenue requirements by $6.7 million per year, as shown in Schedule KCH-5.

## V. Purchased Power and Fuel Adjustment Clause

**Q. What has TEP proposed with respect to a Purchased Power and Fuel Adjustment Clause?**

A. As explained in the direct testimony of Mr. Pignatelli and Mr. Hutchens, TEP is seeking approval of a PPFAC that would provide recovery (or return) of 100 percent of the difference between the actual cost of fuel and purchased power and the Base Cost of Fuel and Purchased Power.[12] TEP proposes that the Base Cost of Fuel and Purchased Power in this proceeding be established using a 2009 forecast, and that, consequently, the PPFAC rate be set at zero for 2009. The PPFAC rate for 2010 would be comprised of two components: (1) a Forward Component, which would be set equal to the difference between the projected fuel cost in 2010 and the Base Cost of Fuel and Purchased Power (previously established for 2009); and (2) a True-Up Component, which would correct for over- or under-recovery of actual costs from the prior year.

In addition to providing for recovery of 100 percent of the difference between the actual cost of fuel and purchased power and the Base Cost of Fuel and Purchased Power, TEP is proposing that 90 percent of the revenues (and 100 percent of the costs) of short-term sales be included in the PPFAC rate.

**Q. What general observations do you have regarding fuel adjustment clauses?**

A. A fuel adjustment clause calls out specific expenses for recovery that are not included in rates when rates are set pursuant to a general rate proceeding. As such, it is a form of single-issue ratemaking, and should only be applied after carefully weighing the justification for such an approach against its several drawbacks.

**Q. What is single-issue ratemaking?**

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[12] For ease of exposition, I will occasionally refer to Base Cost of Fuel and Purchased Power simply as "Base Cost".

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in a single cost item considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

Setting rates based on a change in a single cost item runs contrary to the basic principles of traditional utility regulation. When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. For these reasons, single-issue ratemaking, absent a compelling public interest, is generally not sound regulatory practice. I acknowledge, however, that the most frequently-accepted form of single-issue ratemaking is a fuel adjustment clause, such as that requested by TEP.

**Q. Do you have any other general observations regarding fuel adjustment clauses?**

A. Yes. Because these mechanisms simply pass through changes in cost to customers, there is a valid concern that adoption of a fuel adjustment clause would reduce a utility's incentive to manage its costs as well as it would manage them if the utility remained fully responsible for the cost risk. This reduced incentive to manage costs is another important reason for a regulatory commission to proceed with great caution before adopting a fuel adjustment clause.

**Q. In your experience, do utilities tend to dispute the argument that fuel adjustment clauses reduce a utility's incentive to manage its costs?**

A. Yes. It is not unusual for utility management to argue that the adoption of a fuel adjustment clause would not reduce its incentive to manage costs effectively, and Mr. Hutchens makes such an argument on TEP's behalf in this case. Yet, at the same time, utilities, including TEP, often assert that they should share in the benefit of short-term sales, in order to provide a proper incentive to engage in such transactions. I submit that these positions are inconsistent. If it is true that a particular organization requires a financial incentive in order to maximize its off-system sales revenues for the benefit of its customers, then it is likely also to be true that the same organization requires a financial incentive to reasonably minimize its power costs for the benefit of its customers.

**Q. In light of the concerns you have identified with respect to single-issue ratemaking and reduced incentive to manage costs, what factors should a commission consider if it is asked to approve a fuel adjustment clause?**

A. Commissions should consider three basic questions before adopting a fuel adjustment clause:

1. Are the costs that would be recovered through a fuel adjustment clause subject to significant volatility from year to year?
2. Are the costs in question largely beyond the control of management?
3. Are the costs that could be recovered through a fuel adjustment clause substantial enough to have a material impact on the utility's revenue requirement and financial health between rate cases if they were to go unrecovered?

**Q. Does TEP address these three basic questions in its proposal for a PPFAC?**

A. TEP addresses these questions in a general way, noting for example, the Company's increasing reliance on natural gas as a fuel. At the same time, TEP does not present a great deal of quantitative analysis addressing its financial exposure to fuel price volatility.

**Q. What is your assessment of TEP's PPFAC proposal?**

A. I am neither recommending for nor against adoption of a PPFAC for TEP. In my opinion, TEP has not produced compelling quantitative evidence demonstrating its financial exposure to fuel volatility. At the same time, I am aware of the significant exposure to fuel volatility faced by the other major jurisdictional utility, APS, and acknowledge the possibility that TEP may also face material exposure in this regard.

**Q. If a PPFAC is adopted, do you recommend any changes to the proposal put forward by TEP?**

A. Yes. If a PPFAC is adopted, then I recommend the following modifications to the structure proposed by TEP:

1. As I discussed in the previous section of my testimony, the Base Cost of Fuel and Purchased Power should include a credit to customers for 100 percent of the margins from off-system sales during the test year. (In contrast, TEP's proposal excludes all short-term sales margins from the Base Cost of Fuel and Purchased Power.)

2. Rather than setting each year's fuel and purchased power recovery based on a forecast, as TEP proposes, the PPFAC rate should simply recover the difference

between actual purchased power and fuel costs and the Base Cost of Fuel and Purchased Power. (In other words, the Forward Component should be eliminated from the calculation of the PPFAC rate.)

3. To maintain incentives for the utility to manage its costs effectively, responsibility for changes in fuel and purchased power costs should be shared between the utility and customers. I recommend a 90/10 sharing between customers and TEP.

4. The same 90/10 sharing percentage used for fuel and purchased power should be applied to changes in off-system sales margins (relative to the margins included in the Base Cost of Fuel and Purchased Power).

5. The PPFAC rate charged to customers should be differentiated by voltage level to properly reflect line loss differences among customers taking service at different voltage levels.

**Q. Why should the Base Cost of Fuel and Purchased Power reflect 100 percent of the margins from short-term sales?**

A. The Base Cost of Fuel and Purchased Power is the starting point for calculating the PPFAC rate. As such, it should reflect the net cost of fuel and purchased power established for the base period, including all margins from short-term sales. Short-term sales are made with assets that are included in rate base, the full cost of which is allocated to customers. Consequently, the full value of the test-year benefit of these sales should be reflected as a credit against customer base rates.

**Q. Have you calculated an adjustment to the Base Cost of Fuel and Purchased Power calculated by TEP?**

A. Yes. TEP Exhibit DGH-8 presents the Company's initial projection of the Base Cost of Fuel and Purchased Power. In Schedule KCH-6, I adjust TEP's calculation to: (1) included short-term sales margins in the Base Cost of Fuel and Purchased Power; and (2) remove the "market-based capacity charge" proposed by TEP for the Luna Energy Facility (discussed in Section IV of my testimony). These two adjustments reduce the projected Base Cost of Fuel and Purchased Power from 3.30 cents/kWh to 2.88 cents/kWh.

**Q. Why should the Forward Component be eliminated from the calculation of the PPFAC rate?**

A. According to the approach proposed by TEP, fuel and purchased power costs in rates would always be based on a forecast. In my view, it is not necessary or desirable to introduce this level of conjecture into the rate setting process each year. The primary objective of a PPFAC is to protect the utility from fuel and purchased power price volatility. That objective is fully accomplished using an approach that simply recovers the difference between actual costs and Base Costs, applying an after-the-fact calculation.

**Q Why should responsibility for fuel and purchased power costs above (or below) Base Costs be shared between TEP and its customers?**

A A sharing mechanism is an effective means for addressing the disincentive for effective cost management that is otherwise introduced with a fuel adjustment clause. A pass-through of 100 percent of costs dulls the utility's incentive to manage its costs effectively. Some cost-sharing responsibility maintains that incentive. The 90/10 sharing approach I am recommending strikes a balance between protecting the utility's financial health, while also providing for appropriate incentives.

**Q. What is your assessment of TEP's proposal to retain 10 percent of the revenues from short-term sales for shareholders?**

A. The Company's proposal would have customers be responsible for 100 percent of the <u>costs</u> of generating off-system sales while reserving 10 percent of the revenues to shareholders. Such an asymmetrical approach is inherently unreasonable. Customers should not pay for energy used to make short-term sales if the revenue from those sales is credited to shareholders.

**Q. If the proposed PPFAC is adopted, what is the proper approach to sharing short-term sales margins?**

A. I believe there should be consistent treatment between the sharing mechanism (or lack thereof) applied to deviations in fuel and purchased power expense and the sharing mechanism (or lack thereof) applied to deviations in short-term sales margins. Philosophically, I support approaches that provide direct incentives both for reasonably minimizing energy costs and for maximizing short-term sales margins. This occurs under traditional regulation with no fuel adjustment clause and with 100 percent retention by the utility of increases in short-term sales margins above the level in base rates. It can also occur if a PPFAC is adopted, and a consistent sharing arrangement between customers and the utility is adopted, e.g., a 90/10 customer-to-shareholder split is adopted both for deviations in fuel and purchased power expense as well as for changes in short-term sales margins. For this reason, I am recommending that if a PPFAC is adopted, changes in short-term sales margins (relative to Base Cost) should be split 90/10 between customers and TEP.

At the same time, if the proposed PPFAC is adopted and it contains no sharing between customers and shareholders for fuel and purchased power expense, then neither should there be any sharing of changes in short-term sales margins. In such a case, 100 percent of any increase in short-term sales margins should flow through the fuel adjustor mechanism to the benefit of customers.

**Q. Why should the PPFAC rate be differentiated by voltage levels?**

A. A fuel adjustment charge should be differentiated by voltage for the same reasons that base rates reflect voltage differences: customers taking service at higher voltages incur fewer line losses. Consequently, higher voltage customers require fewer kilowatt-hours of generation to meet a given level of energy consumption delivered to their meters. The PPFAC rates for customers should be designed to reflect these line loss differences.

## VI. True-Up Revenues

**Q. What does Decision No. 69568 require with respect to the treatment of True-Up Revenues?**

A. As discussed in Section IV of my testimony, in Decision No. 69568, the Commission determined that rates will not be reduced by the amount of the Fixed CTC at such time that $450 million in stranded cost is recovered, as originally intended. Instead, the Decision provided that TEP customers should be protected by providing for a mechanism to refund or credit the revenues, plus interest, that will continue to be collected by the modified treatment of the Fixed CTC, until new rates are approved. These revenues are called True-Up Revenues. TEP estimates that approximately $66 million of True-Up Revenues will be collected between May 2008 and December 31, 2008.[13]

**Q. How has TEP proposed to treat the True-Up Revenues?**

A. As explained by Mr. Grant, if the Market Methodology is adopted, then TEP proposes to refund the full amount of True-Up Revenues, plus interest equal to TEP's cost of short-term debt, over a twelve-month period. If the Hybrid Methodology is chosen, TEP proposes that shareholders retain the True-Up Revenues, as part of the "compromise" between the Cost-of-Service and Market Methodologies that the Hybrid Methodology is intended to represent. If the Cost-of-Service Methodology is selected, then TEP similarly seeks to retain the True-Up Revenues, but on the grounds that the $788 million TCRAC regulatory asset claimed by TEP already reflects a reduction of $133 million from what TEP could otherwise claim.[14]

**Q. What is your assessment of TEP's proposed treatment of True-Up Revenues?**

A. I agree that if the Market Methodology is chosen, then the True-Up Revenues should be refunded over a twelve-month period. However, the rate of interest applied should be equal to the rate at which TEP earns on its regulatory

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[13] Direct testimony of Kentton C. Grant, p. 11, line 23 - p. 12, line 1.
[14] Ibid., p. 11, line 19 - p. 13, line 20.

assets. I disagree with TEP's proposed treatment of True-Up Revenues under the Hybrid Methodology and Cost-of-Service Methodology.

**Q. What is your proposed treatment of True-Up Revenues if the Hybrid Methodology is chosen?**

A. I will discuss the Hybrid Methodology further in the next section of my testimony. If this approach is chosen, it will convey a significant benefit to TEP. In such a case, most reasonable treatment of the True-Up Revenues is identical to my recommendation if the Market Methodology is chosen: the True-Up Revenues should be refunded to customers over a twelve-month period, and the rate of interest on this regulatory liability should be equal to the rate at which TEP earns on its regulatory assets.

**Q. What is your proposed treatment of True-Up Revenues if the Cost-of-Service Methodology is chosen?**

A. The True-Up Revenues represent a rate reduction to which customers are entitled by the terms of the 1999 Settlement Agreement. Strictly speaking, these revenues should be applied to the benefit of customers under any scenario.

If a PPFAC is adopted, then I recommend that the True-Up Revenues be applied as a credit against future PPFAC balances. These revenues should earn interest at the interest rate approved for PPFAC balances.

If a PPFAC is not adopted, then I recommend that the True-Up Revenues be returned to customers over a three-year period, and earn interest at the rate applied to TEP's regulatory asset balances.

These two alternative recommendations assume that TEP's proposed TCRAC is rejected by the Commission. If, for some reason, the TCRAC is adopted in whole or in part, then the True-Up Revenues should be applied against the TCRAC balance.

**Q. Do you have any other comments regarding the True-Up Revenues?**

A. Although the True-Up Revenues properly belong to customers, AECC would be willing to accept a resolution in which the True-Up Revenues were <u>not</u> returned to customers under the Cost-of-Service Methodology, <u>if</u>, and <u>only if</u>, this concession were accompanied by TEP's withdrawal of all claims that the Company would be harmed by setting rates at cost-of-service. Absent such action by TEP, the True-Up Revenues should be returned in full to customers.

## VII. <u>Hybrid Methodology</u>

**Q. What has TEP proposed with respect to the Hybrid Methodology?**

A. The Hybrid Methodology is offered by TEP as a middle ground between its Cost-of-Service Methodology and Market Methodology. For the most part, rates would be set in the same manner as in the Cost-of-Service Methodology, except that certain generation assets would be excluded from rate base. Energy from these excluded facilities would be sold to TEP retail customers at market prices. The excluded facilities would be: (1) TEP's interest in the Navajo Generating Stations Units 1, 2, and 3; and (2) TEP's interest in the Four Corners Generating Stations Units 4 and 5. There would be a PPFAC as part of the Hybrid Methodology and TEP is willing to continue direct access service to customers with loads of 3 MW or greater. There would be no TCRAC under the Hybrid Methodology.

**Q. What is your assessment of TEP's Hybrid Methodology proposal?**

A. TEP's Hybrid Methodology proposal is more expensive for customers than the Cost-of-Service Methodology without the TCRAC. At the same time, the impact is less extreme than either the Company's Market Methodology proposal or its Cost-of-Service/TCRAC proposal. However, the Hybrid Methodology proposal is still founded on the premise that TEP is entitled to set rates based on the MGC, a premise that is without foundation.

If the Commission (correctly) concludes that: (1) TEP has no basis to claim that Standard Offer generation rates are to be set equal to the MGC; and (2) the Track A Decision is res judicata, then there is no reason to entertain the Hybrid Methodology any further. Rates would properly be set based on the Cost-of-Service Methodology without the TCRAC. As discussed above, this is my recommendation. However, if the Commission disagrees with my recommendation, then the Hybrid Methodology should be considered, as it is less expensive to customers than either of the alternative proposals as advanced by TEP.

**Q. Are the revenue requirement adjustments you recommended for TEP's Cost-of-Service Methodology applicable to the Hybrid Methodology?**

A. Yes, with the exception of my adjustment to TEP's proposed TCRAC (as the TCRAC is not included in the Hybrid Methodology). Therefore, if the Hybrid Methodology is chosen by the Commission, then I recommend that the

Commission also accept each of my proposed revenue requirement adjustments presented in Section IV of my testimony, with the exception of my TCRAC adjustment.

## VIII. Direct Access Issues

**Q. Do you have any comments with respect to direct access issues in this proceeding?**

A. Yes. TEP's proposals for its Cost-of-Service Methodology and Hybrid Methodology include changes proposed by the Company with respect to direct access rights, namely, that direct access rights for customers be eliminated in the former case and restricted to customers 3 MW and greater in the latter case. I recommend that the Commission reject both of those proposed restrictions. Direct access is a statewide issue. Standard offer generation service in both the APS and SRP service territories is based on cost-of-service, and customers in those territories have not been forced to relinquish their rights to direct access. In fact, APS's generation rates have been designed specifically to avoid prejudicing the direct access decision for customers. If issues of direct access are to be addressed, it should occur in its own docket. Customer direct access rights should not be rolled back piecemeal as part of this proceeding.

**Q. Does this conclude your direct testimony with respect to revenue requirement?**

A. Yes, it does.

**KEVIN C. HIGGINS**
**Principal, Energy Strategies, L.L.C.**
**215 South State St., Suite 200, Salt Lake City, UT 84111**

**Vitae**

## PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

## EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

## SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

**EXPERT TESTIMONY**

"Commonwealth Edison Company Proposed General Increase in Electric Rates," **Illinois** Commerce Commission, Docket No. 07-0566. Direct testimony submitted February 11, 2008.

"In the Matter of the Application of Questar Gas Company to File a General Rate Case," **Utah** Public Service Commission, Docket No. 07-057-13, Direct testimony submitted January 28, 2008 (test period). Cross examined February 8, 2008 (test period).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge," **Utah** Public Service Commission, Docket No. 07-035-93. Direct testimony submitted January 25, 2008 (test period). Cross examined February 7, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals," Public Utilities Commission of **Ohio**, Case Nos. 07-551-EL-AIR, 07-552-EL-ATA, 07-553-EL-AAM, and 07-554-EL-UNC. Direct testimony submitted January 10, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming, Consisting of a General Rate Increase of Approximately $36.1 Million per Year, and for Approval of a New Renewable Resource Mechanism and Marginal Cost Pricing Tariff," **Wyoming** Public Service Commission, Docket No. 20000-277-ER-07. Direct testimony submitted January 7, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service to Electric Customers in the State of Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-07-8. Direct testimony submitted December 10, 2007. Cross examined January 23, 2008.

"In The Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution Of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-15245. Direct testimony submitted November 6, 2007. Rebuttal testimony submitted November 20, 2007.

"In the Matter of Montana-Dakota Utilities Co., Application for Authority to Establish Increased Rates for Electric Service," **Montana** Public Service Commission, Docket No. D2007.7.79. Direct testimony submitted October 24, 2007.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 334," **New Mexico** Public Regulation Commission, Case No. 07-0077-UT. Direct testimony submitted October 22, 2007. Rebuttal testimony submitted November 19, 2007. Cross examined December 12, 2007.

"In The Matter of Georgia Power Company's 2007 Rate Case," **Georgia** Public Service Commission, Docket No. 25060-U. Direct testimony submitted October 22, 2007. Cross examined November 7, 2007.

"In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs Related to the MidAmerican Energy Holdings Company Transaction," **Utah** Public Service Commission, Docket No. 07-035-04; "In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for a Deferred Accounting Order To Defer the Costs of Loans Made to Grid West, the Regional Transmission Organization," Docket No. 06-035-163; "In the Matter of the Application of Rocky Mountain Power for an Accounting Order for Costs related to the Flooding of the Powerdale Hydro Facility," Docket No. 07-035-14. Direct testimony submitted September 10, 2007. Surrebuttal testimony submitted October 22, 2007. Cross examined October 30, 2007.

"In the Matter of General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.," **Kentucky** Public Service Commission, Case No. 2006-00472. Direct testimony submitted July 5, 2007.

"In the Matter of the Application of Sempra Energy Solutions for a Certificate of Convenience and Necessity for Competitive Retail Electric Service," **Arizona** Corporation Commission, Docket No. E-03964A-06-0168. Direct testimony submitted July 3, 2007. Rebuttal testimony submitted January 17, 2008.

"Application of Public Service Company of Oklahoma for a Determination that Additional Electric Generating Capacity Will Be Used and Useful," **Oklahoma** Corporation Commission, Cause No. PUD 200500516; "Application of Public Service Company of Oklahoma for a Determination that Additional Baseload Electric Generating Capacity Will Be Used and Useful," Cause No. PUD 200600030; "In the Matter of the Application of Oklahoma Gas and Electric Company for an Order Granting Pre-Approval to Construct Red Rock Generating Facility and Authorizing a Recovery Rider," Cause No. PUD200700012. Responsive testimony submitted May 21, 2007. Cross examined July 26, 2007.

"Application of Nevada Power Company for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto," Public Utilities Commission of **Nevada**, Docket No. 06-11022. Direct testimony submitted March 14, 2007 (Phase III – revenue requirements) and March 19, 2007 (Phase IV – rate design). Cross examined April 10, 2007 (Phase III – revenue requirements) and April 16, 2007 (Phase IV – rate design).

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission, Docket No. 06-101-U. Direct testimony submitted February 5, 2007. Surrebuttal testimony submitted March 26, 2007.

"Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Rule 42T Application to Increase Electric Rates and Charges," Public Service Commission of **West Virginia**, Case No. 06-0960-E-42T; "Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Information Required for Change of Depreciation Rates Pursuant to Rule 20," Case No. 06-1426-E-D. Direct and rebuttal testimony submitted January 22, 2007.

"In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Missouri Service Areas," **Missouri** Public Service Commission, Case No. ER-2007-0004. Direct testimony submitted January 18, 2007 (revenue requirements) and January 25, 2007 (revenue apportionment). Supplemental direct testimony submitted February 27, 2007.

"In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103, **Arizona** Corporation Commission, Docket No. E-01933A-05-0650. Direct testimony submitted January 8, 2007. Surrebuttal testimony filed February 8, 2007. Cross examined March 8, 2007.

"In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area," **Missouri** Public Service Commission, Case No. ER-2007-0002. Direct testimony submitted December 15, 2006 (revenue requirements) and December 29, 2006 (fuel adjustment clause/cost-of-service/rate design). Rebuttal testimony submitted February 5, 2007 (cost-of-service). Surrebuttal testimony submitted February 27, 2007. Cross examined March 21, 2007.

"In the Matter of Application of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. for an Adjustment of Electric Rates," **Kentucky** Public Service Commission, Case No. 2006-00172. Direct testimony submitted September 13, 2006.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2006-00065. Direct testimony submitted September 1, 2006. Cross examined December 7, 2006.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes, to Fix a Just and Reasonable

Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744, **Arizona** Corporation Commission," Docket No. E-01345A-05-0816. Direct testimony submitted August 18, 2006 (revenue requirements) and September 1, 2006 (cost-of-service/rate design). Surrebuttal testimony submitted September 27, 2006. Cross examined November 7, 2006.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No 1454 – Electric," **Colorado** Public Utilities Commission, Docket No. 06S-234EG. Answer testimony submitted August 18, 2006.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-180. Direct testimony submitted August 9, 2006. Joint testimony regarding stipulation submitted August 22, 2006.

"2006 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006. Joint testimony regarding stipulation submitted August 23, 2006.

"In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE-179. Direct testimony submitted July 12, 2006. Joint testimony regarding stipulation submitted August 21, 2006.

"Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan," **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; "Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan," Docket Nos. P-0062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006. Surrebuttal testimony submitted August 18, 2006. Cross examined August 30, 2006.

"In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations," **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

"Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders," **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted May 15, 2006. Rebuttal testimony submitted August 8, 2007. Cross examined September 19, 2007.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Power Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct and rebuttal testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No. G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase," **Arizona** Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska**, Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company," **Kentucky** Public Service Commission, Case No. 2003-00434. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company," **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

"In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period," Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchased Power Contract," **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada,** PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-

0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01. Direct testimony submitted July 8, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

**OTHER RELATED ACTIVITY**

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to December 1999. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, <u>Economic Forum</u>, September 1980 to August 1981.

# Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2006
(Thousands of Dollars)

## As Filed by TEP

| Line No. | Description | ACC Jurisdiction Original Cost Excluding DSM & CTC | | Excluding CTC Including DSM | | Including DSM & CTC | | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1 | Adjusted Rate Base | $982,734 | (a) | $982,734 | | $982,734 | | 1 |
| 2 | Adjusted Operating Income | (13,173) | (b) | ($9,883) | | $44,082 | | 2 |
| 3 | Current Rate of Return (2/1) | -1.34% | | -1.01% | | 4.49% | | 3 |
| 4 | Required Operating Income | $82,069 | | $82,069 | | $82,069 | | 4 |
| 5 | Required Rate of Return (4/1) | 8.35% | (c) | 8.35% | | 8.35% | | 5 |
| 6 | Operating Income Deficiency | $95,242 | | $91,952 | | $37,987 | | 6 |
| 7 | Gross Revenue Conversion Factor | 1.6609 | (d) | 1.6609 | | 1.6609 | | 7 |
| 8 | Increase in Gross Revenue Requirement Excluding TCRAC (6 x 7) | $158,186 | | $152,721 | | $63,091 | | 8 |
| 9 | Present Revenues | $691,451 | (e) | $696,916 | (e) | $786,546 | (e) | 9 |
| 10 | Percent Change from Present Revs. (8/9) | 22.88% | | 21.91% | | 8.02% | | 10 |
| 11 | Termination Cost Regulatory Asset Revenue (TCRAC) | $117,623 | (f) | $117,623 | (f) | $117,623 | (f) | |
| 12 | Increase in Gross Revenue Requirement Including TCRAC (8 + 11) | $275,809 | | $270,344 | | $180,714 | | 11 |
| 13 | Percent Change from Present Revs. (12/9) | 39.89% | | 38.79% | | 22.98% | | 12 |

Supporting Schedules
(a) TEP Schedule B-1
(b) TEP Schedule C-1
(c) TEP Schedule D-1
(d) TEP Schedule C-3
(e) TEP Schedule H-1
(f) TEP Schedule H-2 TCRAC, p. 3 of 3 Workpaper

# Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2006
(Thousands of Dollars)

## As Adjusted by AECC

| Line No. | Description | ACC Jurisdiction Original Cost Excluding DSM & CTC | | Excluding CTC Including DSM | Including DSM & CTC | Line No. |
|---|---|---|---|---|---|---|
| 1 | Adjusted Rate Base | $1,018,008 | (a)&(b) | $1,018,008 | $1,018,008 | 1 |
| 2 | Adjusted Operating Income | 29,852 | (c) | $33,142 | $87,107 | 2 |
| 3 | Current Rate of Return (2/1) | 2.93% | | 3.26% | 8.56% | 3 |
| 4 | Target Operating Income (5 x 1) | $85,015 | | $85,015 | $85,015 | 4 |
| 5 | Target Rate of Return | 8.35% | (d) | 8.35% | 8.35% | 5 |
| 6 | Operating Income Deficiency (4 - 2) | $55,163 | | $51,873 | ($2,093) | 6 |
| 7 | Gross Revenue Conversion Factor | 1.6609 | (e) | 1.6609 | 1.6609 | 7 |
| 8 | Increase in Gross Revenue Requirement (6 x 7) | $91,619 | | $86,154 | ($3,476) | 8 |
| 9 | Present Revenues | $691,451 | (f) | $696,916 | $786,546 | 9 |
| 10 | Percent Change from Present Revs. (8/9) | 13.25% | | 12.36% | -0.44% | 10 |
| 11 | TEP Claimed Revenue Deficiency | $275,809 | | $270,344 | $180,714 | 11 |
| 12 | Percent Change from Present Revs. (11/9) | 39.89% | | 38.79% | 22.98% | 12 |
| 13 | AECC Change from TEP Claimed Revenue Deficiency (8 - 11) | ($184,190) | | ($184,190) | ($184,190) | 13 |
| 14 | AECC Percent Change from TEP Claimed Revenue Deficiency (10 - 12) | -26.64% | | -26.43% | -23.42% | 14 |

Supporting Schedules
(a) TEP Schedule B-1
(b) AECC Schedule KCH-1, p. 4
(c) AECC Schedule KCH-1, p. 3
(d) TEP Schedule D-1
(e) TEP Schedule C-3
(f) TEP Schedule H-1

# Summary of AECC Revenue Requirement Adjustments

## Operating Revenues and Expenses
Test Year Ended December 31, 2006
(Thousands of Dollars)

| Line No. | Description | TEP Unadjusted (a) | TEP Pro Forma Adjustments (a) | TEP Total Adjusted (a) | TEP ACC Jurisdiction (a) | AECC Springerville No. 1 Pro Forma Adjustment (b) | AECC Short Term Sales Reversal (b) | AECC Implementation Cost Regulatory Asset (b) | AECC Luna Plant Adjustment Reversal (b) | AECC ACC Jurisdiction | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Operating Revenues | | | | | | | | | | |
| 1 | Electric Retail Revenues | $774,470 | ($83,019) | $691,451 | $691,451 | $0 | $0 | 0 | 0 | $691,451 | 1 |
| 2 | Sales for Resale | 242,187 | (183,785) | 58,402 | 0 | 0 | $73,439 | 0 | 0 | $73,439 | 2 |
| 3 | Other Operating Revenue | 48,764 | ($14,222) | 34,542 | 21,280 | 0 | $0 | 0 | 0 | $21,280 | 3 |
| 4 | Total Operating Revenues | 1,065,421 | (281,026) | 784,395 | 712,731 | 0 | 73,439 | 0 | 0 | 786,170 | 4 |
| | Operating Expenses | | | | | | | | | | |
| 5 | Fuel Expense | 278,776 | (12,821) | 265,955 | 238,199 | 0 | 28,799 | 0 | 0 | $266,998 | 5 |
| 6 | Purchased Power - Demand | 13,740 | 16,894 | 30,634 | 28,959 | 0 | 0 | 0 | (15,088) | $13,872 | 6 |
| 7 | Purchased Power - Energy | 163,607 | (123,572) | 40,035 | 35,857 | 0 | 20,762 | 0 | 0 | $56,618 | 7 |
| 8 | Other Operations and Maintenance Expense | 326,699 | (11,596) | 315,103 | 368,170 | (30,357) | 0 | 0 | 1,981 | $339,794 | 8 |
| 9 | Depreciation | 89,928 | (7,488) | 82,440 | 57,914 | 0 | 0 | (3,900) | 0 | $54,014 | 9 |
| 10 | Taxes Other than Income Taxes | 38,404 | (2,573) | 35,831 | 29,092 | 0 | 0 | 0 | 8 | $29,100 | 10 |
| 11 | Income Taxes | 46,292 | (58,553) | (12,261) | (32,286) | 12,021 | 9,456 | 1,544 | 5,187 | ($4,078) | 11 |
| 12 | Total Operating Expenses | 957,446 | (199,708) | 757,738 | 725,904 | (18,336) | 59,016 | (2,355) | (7,912) | 756,318 | 12 |
| 13 | Operating Income | 107,975 | ($81,318) | $26,657 | ($13,173) | $18,336 | $14,423 | $2,355 | $7,912 | $29,852 | 13 |
| | Other Income and Deductions | | | | | | | | | | |
| 14 | Allowance for Equity Funds | 1,476 | | | | | | | | | |
| 15 | Other - Net | 11,789 | | | | | | | | | |
| 16 | Total Other Income and Deductions | 13,265 | | | | | | | | | |
| 17 | Income Before Interest Expense | 121,240 | | | | | | | | | |
| | Interest Expense | | | | | | | | | | |
| 18 | Interest on Long-Term Debt | 44,102 | | | | | | | | | |
| 19 | Interest on Short-Term Debt | 1,216 | | | | | | | | | |
| 20 | Other Interest Expense | 10,447 | | | | | | | | | |
| 21 | Allowance for Borrowed Funds | (1,270) | | | | | | | | | |
| 22 | Total Interest Expense | 54,495 | | | | | | | | | |
| 23 | Income Before Cumulative Effect of Accounting Change | 66,745 | | | | | | | | | |
| 24 | Cumulative Effect of Accounting Change - Net of Tax | 0 | | | | | | | | | |
| 25 | Net Income Available for Common Stock | $66,745 | | | | | | | | | |

| Supporting Schedules | Recap Schedules |
|---|---|
| (a) TEP Schedule C-1 | |
| (b) AECC Schedule KCH-1, p. 4 | |

# Summary of AECC Revenue Requirement Adjustments

## AECC Recommended Rate Base Adjustments

| Line No. | | ACC Jurisdiction: AECC Add'l Springerville Unit No. 1 (a) | AECC Short Term Sales Exclusion Reversal (b) | AECC Implementation Cost Regulatory Asset (c) | AECC Luna Plant Adjustment Reversal (d) | Line No. |
|---|---|---|---|---|---|---|
| 1 | Rate Base | 0 | 0 | (11,181) | 46,456 | 1 |

## AECC Recommended Revenue and Expense Adjustments

| Line No. | | ACC Jurisdiction: AECC Add'l Springerville Unit No. 1 (a) | AECC Short Term Sales Exclusion Reversal (b) | AECC Implementation Cost Regulatory Asset (c) | AECC Luna Plant Adjustment Reversal (d) | Line No. |
|---|---|---|---|---|---|---|
| 2 | Operating Revenues | | | | | 2 |
| 3 | Electric Retail Revenues | 0 | 0 | 0 | 0 | 3 |
| 4 | Sales for Resale | 0 | 73,439 | 0 | 0 | 4 |
| 5 | Other Operating Reveue | 0 | 0 | 0 | 0 | 5 |
| 6 | Total Operating Revenues | 0 | 73,439 | 0 | 0 | 6 |
| 7 | Operating Expenses | | | | | 7 |
| 8 | Fuel Expense | 0 | 28,799 | 0 | 0 | 8 |
| 9 | Purchased Power - Demand | 0 | 0 | 0 | (15,088) | 9 |
| 10 | Purchased Power - Energy | 0 | 20,762 | 0 | 0 | 10 |
| 11 | Other Operations & Maintenance Expense | (30,357) | 0 | 0 | 1,981 | 11 |
| 12 | Depreciation and Amortization | 0 | 0 | (3,900) | 0 | 12 |
| 13 | Taxes Other than Income | 0 | 0 | 0 | 8 | 13 |
| 14 | Income Taxes | 12,021 | 9,456 | 1,544 | 5,187 | 14 |
| 15 | Total Operating Expenses | (18,336) | 59,016 | (2,355) | (7,912) | 15 |
| 16 | Operating Income | 18,336 | 14,423 | 2,355 | 7,912 | 16 |

Supporting Schedules
(a) AECC Schedule KCH-2, p. 1
(b) AECC Schedule KCH-3, p. 1
(c) AECC Schedule KCH-4, p. 1
(d) AECC Schedule KCH-5, p. 1

# AECC Adjustment to Springerville Unit No. 1 Fixed Cost Recovery

| | | |
|---|---|---|
| Jurisdictional Demand Allocation Factor | 94.53% | (b) |
| Jurisdictional O&M Allocation Factor | 95.68% | (b) |

| Line No. | | Total Company<br>AECC Springerville Unit No. 1<br>(a) | | Jurisdictional<br>AECC Springerville Unit No. 1 | | Line No. |
|---|---|---|---|---|---|---|
| 1 | Operating Revenues | | | | | 1 |
| 2 | Electric Retail Revenues | 0 | | 0 | | 2 |
| 3 | Sales for Resale | 0 | | 0 | | 3 |
| 4 | Other Operating Reveue | 0 | | 0 | | 4 |
| 5 | Total Operating Revenues | 0 | | 0 | | 5 |
| 6 | Operating Expenses | | | | | 6 |
| 7 | Fuel Expense | 0 | | 0 | | 7 |
| 8 | Purchased Power - Demand | 0 | | 0 | | 8 |
| 9 | Purchased Power - Energy | 0 | | 0 | | 9 |
| 10 | Other Operations & Maintenance Expense | (32,095) | | (30,357) | | 10 |
| 11 | Depreciation and Amortization | 0 | | 0 | | 11 |
| 12 | Taxes Other than Income | 0 | | 0 | | 12 |
| 13 | Income Taxes | 12,710 | | 12,021 | | 13 |
| 14 | Total Operating Expenses | (19,385) | | (18,336) | | 14 |
| 15 | Operating Income | 19,385 | | 18,336 | | 15 |
| 16 | Gross Revenue Conversion Factor | | | 1.6609 | (c) | 16 |
| 17 | Impact on Revenue Requirement (-15 x 16) | | | (30,453) | | 17 |

| Income Tax Calculation | | | | |
|---|---|---|---|---|
| Change in Revenue | 0 | | 0 | |
| Change in O&M Expenses | (32,095) | | (30,357) | |
| Change in Depreciation and Amortization | 0 | | 0 | |
| Change in Taxes, Other than Income | 0 | | 0 | |
| Change in Operating Income Before Income Taxes | 32,095 | | 30,357 | |
| Income Tax Adjustments: | | | | |
| Change in Net Schedule M Items | 0 | | 0 | |
| Change in Synchronized Interest | 0 | | 0 | |
| Change in Taxable Operating Income | 32,095 | | 30,357 | |
| Effective FIT & SIT Tax Rate | 39.600% | (c) | 39.600% | (c) |
| Change in Income Tax Expense Before Credits | 12,710 | | 12,021 | |
| Change in Income Tax Credits | 0 | | 0 | |
| Total Change in Income Taxes | 12,710 | | 12,021 | |

Supporting Schedules/Data Source
(a) TEP Income - Springerville Unit 1.xls
(b) 2007 TEP Rev Req Model.xls
(c) TEP Schedule C-3

# Adjustment to Springerville Unit No. 1 Fixed Cost Recovery
# Test Year Ended December 31, 2006

| Line No. (a) | (b) | FERC (c) | (d) | TEP G/L[1] (e) | TEP Proposed Allowed[1] (f) | TEP Adjustment[1] (g) | AECC Proposed Allowed (h) | AECC Adjustment to TEP Proposed (i) | Line No. (j) |
|---|---|---|---|---|---|---|---|---|---|
| | Operations & Maintenance | | | | | | | | |
| 1 | | 500 | | $630,417 | $868,566 | $238,149 | $630,417 | ($238,149) | 1 |
| 2 | | 502 | | $6,495,149 | $8,948,779 | $2,453,630 | $6,495,149 | ($2,453,630) | 2 |
| 3 | | 505 | | $502,754 | $692,677 | $189,922 | $502,754 | ($189,922) | 3 |
| 4 | | 506 | | $974,565 | $1,342,720 | $368,155 | $974,565 | ($368,155) | 4 |
| 5 | | 507 | Lease Expense | $61,857,188 | $85,224,576 | $23,367,388 | $61,857,188 | ($23,367,388) | 5 |
| 6 | | 510 | | $761,665 | $1,049,394 | $287,729 | $761,665 | ($287,729) | 6 |
| 7 | | 511 | | $503,659 | $693,923 | $190,264 | $503,659 | ($190,264) | 7 |
| 8 | | 512 | | $6,860,839 | $9,452,613 | $2,591,774 | $6,860,839 | ($2,591,774) | 8 |
| 9 | | 513 | | $1,071,214 | $1,475,879 | $404,665 | $1,071,214 | ($404,665) | 9 |
| 10 | | 514 | | $1,575,182 | $2,170,229 | $595,046 | $1,575,182 | ($595,046) | 10 |
| 11 | | O&M Sub-Total | | $81,232,631 | $111,919,355 | $30,686,724 | $81,232,631 | ($30,686,724) | 11 |
| | Administrative & General | | | | | | | | |
| 12 | | 920 | | $767,057 | $1,056,823 | $289,766 | $767,057 | ($289,766) | 12 |
| 13 | | 921 | | $289,224 | $398,482 | $109,258 | $289,224 | ($109,258) | 13 |
| 14 | | 923 | | $187,116 | $257,801 | $70,686 | $187,116 | ($70,686) | 14 |
| 15 | | 924 | | $517,624 | $713,164 | $195,540 | $517,624 | ($195,540) | 15 |
| 16 | | 925 | | $72,478 | $99,857 | $27,379 | $72,478 | ($27,379) | 16 |
| 17 | | 926 | | $1,843,918 | $2,540,483 | $696,565 | $1,843,918 | ($696,565) | 17 |
| 18 | | 930 | | $34,507 | $47,543 | $13,036 | $34,507 | ($13,036) | 18 |
| 19 | | 931 | | $15,744 | $21,691 | $5,947 | $15,744 | ($5,947) | 19 |
| 20 | | A&G Sub-Total | | $3,727,668 | $5,135,845 | $1,408,177 | $3,727,668 | ($1,408,177) | 20 |
| 21 | Total Adjustment to Cost of Service | | | $84,960,299 | $117,055,200 | $32,094,901 | $84,960,299 | ($32,094,901) | 21 |
| 22 | SP Unit 1 Nameplate Rating (MW) | | | 380 | | | | | 22 |
| 23 | Cost per kW per Year | | | $223.58 | = [O&M + A&G] / Rating (MW) = Ln 21 ÷ [Ln 22 x 1000] | | | | 23 |
| 24 | Cost per kW per Month | | | $18.63 | = Cost per MW per year ÷ 12 = Ln 23 ÷ 12 | | | | 24 |

Calculation of Proposed Springerville Unit #1 Allowed Expenses

| Line | | | | | | | | | | Line |
|---|---|---|---|---|---|---|---|---|---|---|
| 25 | (a) TEP Proposed Allowed SP1 Expenses | $25.67 | x | 380 | x | 12 | x | 1,000 | = $117,055,200 | 25 |
| 26 | (b) AECC Proposed Allowed SP1 Expenses | $18.63 | x | 380 | x | 12 | x | 1,000 | = $84,960,299 | 26 |

Data Source
(1) TEP Pro Forma Adjustment Workpaper "Income - Springerville Unit 1.xls"

# AECC Adjustment to Short Term Sales Margin

Jurisdictional Demand Allocation Factor 94.53% (b)

| Line No. | | Total Company: AECC Short Term Sales Exclusion Reversal (a) | | Jurisdictional: AECC Short Term Sales Exclusion Reversal | | Line No. |
|---|---|---|---|---|---|---|
| 1 | Operating Revenues | | | | | 1 |
| 2 | Electric Retail Revenues | 0 | | 0 | | 2 |
| 3 | Sales for Resale | 77,685 | | 73,439 | | 3 |
| 4 | Other Operating Reveue | 0 | | 0 | | 4 |
| 5 | Total Operating Revenues | 77,685 | | 73,439 | | 5 |
| 6 | Operating Expenses | | | | | 6 |
| 7 | Fuel Expense | 30,464 | | 28,799 | | 7 |
| 8 | Purchased Power - Demand | 0 | | 0 | | 8 |
| 9 | Purchased Power - Energy | 21,962 | | 20,762 | | 9 |
| 10 | Other Operations & Maintenance Expense | 0 | | 0 | | 10 |
| 11 | Depreciation and Amortization | 0 | | 0 | | 11 |
| 12 | Taxes Other than Income | 0 | | 0 | | 12 |
| 13 | Income Taxes | 10,003 | | 9,456 | | 13 |
| 14 | Total Operating Expenses | 62,429 | | 59,016 | | 14 |
| 15 | Operating Income | 15,256 | | 14,423 | | 15 |
| 16 | Gross Revenue Conversion Factor | | | 1.6609 | (c) | 16 |
| 17 | Impact on Revenue Requirement (-17 x 18) | | | (23,954) | | 17 |

| | Total Company | | Jurisdictional | |
|---|---|---|---|---|
| <u>Income Tax Calculation</u> | | | | |
| Change in Revenue | 77,685 | | 73,439 | |
| Change in O&M Expenses | 52,426 | | 49,561 | |
| Change in Depreciation and Amortization | 0 | | 0 | |
| Change in Taxes, Other than Income | 0 | | 0 | |
| Change in Operating Income Before Income Taxes | 25,259 | | 23,878 | |
| Income Tax Adjustments: | | | | |
| Change in Net Schedule M Items | 0 | | 0 | |
| Change in Synchronized Interest | 0 | | 0 | |
| Change in Taxable Operating Income | 25,259 | | 23,878 | |
| Effective FIT & SIT Tax Rate | 39.600% | (c) | 39.600% | (c) |
| Change in Income Tax Expense Before Credits | 10,003 | | 9,456 | |
| Change in Income Tax Credits | 0 | | 0 | |
| Total Change in Income Taxes | 10,003 | | 9,456 | |

<u>Supporting Schedules/Data Source</u>
(a) TEP Schedule C-2, p. 2 of 8
(b) 2007 TEP Rev Req Model.xls
(c) TEP Schedule C-3

# AECC Adjustment to Implementation Cost Regulatory Asset

| Line No. | | Total Company AECC Implementation Cost Regulatory Asset (a) | Jurisdictional AECC Implementation Cost Regulatory Asset | | Line No. |
|---|---|---|---|---|---|
| | Jurisdictional Allocation Factor | | 100.00% | (b) | |
| 1 | Rate Base | (11,181) | (11,181) | | 1 |
| 2 | Operating Revenues | | | | 2 |
| 3 | Electric Retail Revenues | 0 | 0 | | 3 |
| 4 | Sales for Resale | 0 | 0 | | 4 |
| 5 | Other Operating Reveue | 0 | 0 | | 5 |
| 6 | Total Operating Revenues | 0 | 0 | | 6 |
| 7 | Operating Expenses | | | | 7 |
| 8 | Fuel Expense | 0 | 0 | | 8 |
| 9 | Purchased Power - Demand | 0 | 0 | | 9 |
| 10 | Purchased Power - Energy | 0 | 0 | | 10 |
| 11 | Other Operations & Maintenance Expense | 0 | 0 | | 11 |
| 12 | Depreciation and Amortization | (3,900) | (3,900) | | 12 |
| 13 | Taxes Other than Income | 0 | 0 | | 13 |
| 14 | Income Taxes | 1,544 | 1,544 | | 14 |
| 15 | Total Operating Expenses | (2,355) | (2,355) | | 15 |
| 16 | Operating Income | 2,355 | 2,355 | | 16 |
| 17 | Gross Revenue Conversion Factor | | 1.6609 | (c) | 17 |
| 18 | Impact on Revenue Requirement (-[16 x 17] + [8.35% x 1 x 17]) | | (5,463) | | 18 |

| | Total Company | | Jurisdictional | |
|---|---|---|---|---|
| **Income Tax Calculation** | | | | |
| Change in Revenue | 0 | | 0 | |
| Change in O&M Expenses | 0 | | 0 | |
| Change in Depreciation and Amortization | (3,900) | | (3,900) | |
| Change in Taxes, Other than Income | 0 | | 0 | |
| Change in Operating Income Before Income Taxes | 3,900 | | 3,900 | |
| Income Tax Adjustments: | | | | |
| Change in Net Schedule M Items | 0 | | 0 | |
| Change in Synchronized Interest | 0 | | 0 | |
| Change in Taxable Operating Income | 3,900 | | 3,900 | |
| Effective FIT & SIT Tax Rate | 39.600% | (c) | 39.600% | (c) |
| Change in Income Tax Expense Before Credits | 1,544 | | 1,544 | |
| Change in Income Tax Credits | 0 | | 0 | |
| Total Change in Income Taxes | 1,544 | | 1,544 | |

Supporting Schedules/Data Source
(a) AECC ICRA Adjustment Workpaper
(b) 2007 TEP Rev Req Model.xls
(c) TEP Schedule C-3

## AECC Regulatory Asset Adjustment
## Test Year Ended December 31, 2006

| | TEP | AECC | AECC Adjustment |
|---|---|---|---|
| **Deferred Direct Access Costs** | | | |
| Balance of regulatory asset in FERC 182.3 (deferred amortization) @ 12/31/06 | $11,153,016 | $11,153,016 | $0 |
| **Total Direct Access Costs to be recovered in Rate Base** | **$11,153,016** | **$11,153,016** | **$0** |
| **TEP Adjustment to test year expense** | **/4** | **/4** | |
| **Amortization of Direct Access Costs over 4 years.** | **$2,788,254** | **$2,788,254** | **$0** |

Explanation of reclass of intangible plant to regulatory asset:
The balance in the regulatory asset represents deferred amortization of the capitalized direct access costs.

---

| | TEP | AECC | AECC Adjustment |
|---|---|---|---|
| **Deferred Divestiture Costs** | | | |
| Balance of regulatory asset in FERC 182.3 (deferred amortization) @ 12/31/06 | $1,193,003 | $1,193,003 | $0 |
| **Total Deferred Divestiture Costs to be recovered in Rate Base** | **$1,193,003** | **$1,193,003** | **$0** |
| **TEP Adjustment to test year expense** | **/4** | **/4** | |
| **Amortization of Deferred Divestiture Costs over 4 years.** | **$298,251** | **$298,251** | **$0** |

Reason for Adjustment
To increase rate base for divestiture costs deferred in accordance with Decision No. 60977 and Decision No. 62103.

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| | TEP | AECC | AECC Adjustment |
|---|---|---|---|
| **Deferred GenCo Seperation Costs** | | | |
| Balance of regulatory asset in FERC 182.3 (deferred amortization) @ 12/31/06 | $164,026 | $164,026 | $0 |
| **Total Deferred GenCo Seperation Costs to be recovered in Rate Base** | **$164,026** | **$164,026** | **$0** |
| **TEP Adjustment to test year expense** | **/4** | **/4** | |
| **Amortization of Deferred GenCo Seperation Costs over 4 years.** | **$41,007** | **$41,007** | **$0** |

Reason for Adjustment
To increase rate base for GenCo separation costs deferred in accordance with Decision No. 62103.

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| | TEP | AECC | AECC Adjustment |
|---|---|---|---|
| **San Juan Coal Contract Amendment** | | | |
| Contract Amendment Fee Paid | $15,413,887 | | |
| Plus Transaction Costs (attorneys fees) | 155,309 | | |
| Less Tax Refund | (838,107) | | |
| **Total San Juan Contract Amendment Fees to be recovered in Rate Base** | **$14,731,089** | **$8,715,894** | **($6,015,195)** |
| **TEP Adjustment to test year expense** | **/4** | **/4** | |
| **Amortization of San Juan Coal Contract Termination Costs over 4 years.** | **$3,682,772** | **$1,473,109** | **($2,209,663)** |

Reason for Adjustment
To reflect in rate base the consideration paid to amend the former coal contract for the San Juan generation station.

## AECC Regulatory Asset Adjustment
## Test Year Ended December 31, 2006

| | TEP | AECC | AECC Adjustment |
|---|---|---|---|
| **Sundt Coal Contract Termination Fee** | | | |
| Contract Fee Paid | $11,250,000 | | |
| Plus Transaction Costs (economic consultant) | 9,934 | | |
| **Total Sundt Coal Contract Termination Fee to be recovered in Rate Base** | **$11,259,934** | **$6,093,750** | **($5,166,184)** |
| **TEP Adjustment to test year expense** | **/4** | **/4** | |
| **Amortization of Sundt Coal Termination Fee over 4 years.** | **$2,814,984** | **$1,125,000** | **($1,689,984)** |

Reason for Adjustment
To reflect in rate base the consideration paid to terminate the coal contract for the Sundt generation station.

| | TEP | AECC | AECC Adjustment |
|---|---|---|---|
| **Deferred Desert Star and West Connect Funding** | | | |
| Desert Star long term receivable | $446,129 | $446,129 | $0 |
| Desert Star long term interest receivable | 251,970 | 251,970 | 0 |
| West Connect charges | 273,445 | 273,445 | 0 |
| Plus Related Outside Counsel Costs | 731,254 | 731,254 | 0 |
| **Total Deferred Desert Star and West Connect Funding to be recovered in Rate Base.** | **$1,702,798** | **$1,702,798** | **$0** |
| **TEP Adjustment to test year expense** | **/4** | **/4** | |
| **Amortization of Deferred Desert Star and West Connect Funding.** | **$425,700** | **$425,700** | **$0** |

Reason for Adjustment
To reflect in rate base the funding and related costs for Desert Star and West Connect.

| | TEP | AECC | AECC Adjustment |
|---|---|---|---|
| **Financing Costs - Generation** | | | |
| Financing Costs - Generation | $7,251,358 | $7,251,358 | $0 |
| **Total Deferred Financing Costs - Generation to be recovered in Rate Base.** | **$7,251,358** | **$7,251,358** | **$0** |
| **TEP Adjustment to test year expense** | **/4** | **/4** | |
| **Amortization of Financing Costs - Generation.** | **$1,812,840** | **$1,812,840** | **$0** |

Reason for Adjustment
To reflect in rate base the financing costs for generation.

| | TEP | AECC | AECC Adjustment |
|---|---|---|---|
| **Total 182.3 Regulatory Assets** | **$47,455,224** | **$36,273,845** | **($11,181,379)** |
| **Annual Amortization** | **$11,863,806** | **$7,964,159** | **($3,899,647)** |

# AECC Adjustment to Luna Plant

| Line No. | | Total Company AECC Luna Plant Adjustment Reversal (a) | | Jurisdictional AECC Luna Plant Adjustment Reversal | | Line No. |
|---|---|---|---|---|---|---|
| | Jurisdictional Demand Allocation Factor | | | 94.53% | (b) | |
| 1 | Rate Base (Luna OCRB + Luna ADIT) | 49,141 | | 46,456 | | 1 |
| 2 | Operating Revenues | | | | | 2 |
| 3 | Electric Retail Revenues | 0 | | 0 | | 3 |
| 4 | Sales for Resale | 0 | | 0 | | 4 |
| 5 | Other Operating Reveue | 0 | | 0 | | 5 |
| 6 | Total Operating Revenues | 0 | | 0 | | 6 |
| 7 | Operating Expenses | | | | | 7 |
| 8 | Fuel Expense | 0 | | 0 | | 8 |
| 9 | Purchased Power - Demand | (15,960) | | (15,088) | | 9 |
| 10 | Purchased Power - Energy | 0 | | 0 | | 10 |
| 11 | Other Operations & Maintenance Expense | 2,096 | | 1,981 | | 11 |
| 12 | Depreciation and Amortization | 0 | | 0 | | 12 |
| 13 | Taxes Other than Income | 8 | | 8 | | 13 |
| 14 | Income Taxes | 5,487 | | 5,187 | | 14 |
| 15 | Total Operating Expenses | (8,369) | | (7,912) | | 15 |
| 16 | Operating Income | 8,369 | | 7,912 | | 16 |
| 17 | Gross Revenue Conversion Factor | | | 1.6609 | (c) | 17 |
| 18 | Impact on Revenue Requirement (-[16 x 17] + [8.35% x 1 x 17]) | | | $\boxed{(6,697)}$ | | 18 |
| | **Income Tax Calculation** | | | | | |
| | Change in Revenue | 0 | | 0 | | |
| | Change in O&M Expenses | (13,864) | | (13,106) | | |
| | Change in Depreciation and Amortization | 0 | | 0 | | |
| | Change in Taxes, Other than Income | 8 | | 8 | | |
| | Change in Operating Income Before Income Taxes | 13,856 | | 13,099 | | |
| | Income Tax Adjustments: | | | | | |
| | Change in Net Schedule M Items | 0 | | 0 | | |
| | Change in Synchronized Interest | 0 | | 0 | | |
| | Change in Taxable Operating Income | 13,856 | | 13,099 | | |
| | Effective FIT & SIT Tax Rate | 39.600% | (c) | 39.600% | (c) | |
| | Change in Income Tax Expense Before Credits | 5,487 | | 5,187 | | |
| | Change in Income Tax Credits | 0 | | 0 | | |
| | Total Change in Income Taxes | 5,487 | | 5,187 | | |

Supporting Schedules/Data Source
(a) TEP Luna Plant and ADIT Adjustment Workpapers
(b) 2007 TEP Rev Req Model.xls
(c) TEP Schedule C-3

# AECC Adjustments to Base Fuel Cost

| Line No. | FERC Account | Expense | TEP Cost of Service ACC Jurisdiction Adjusted $000 | AECC Short Term Sales Reversal $000 | AECC Luna Plant Adjustment Reversal $000 | AECC Cost of Service ACC Jurisdiction Adjusted $000 | Line No. |
|---|---|---|---|---|---|---|---|
| 1 | 447 | Sales for Resale - PPFAC Eligible | $ - | $73,439 (b) | | $73,439 | 1 |
| 2 | 501 | Fuel - PPFAC Eligible | $ 214,138 (a) | 28,799 (b) | | $242,936 | 2 |
| 3 | 547 | Fuel - PPFAC Eligible | $ 24,061 (a) | | | $24,061 | 3 |
| 4 | 555 | Purchase Power, Demand - PPFAC Eligible | $ 28,959 (a) | | (15,088) (b) | $13,872 | 4 |
| 5 | 555 | Purchase Power, Energy - PPFAC Eligible | $ 35,857 (a) | 20,762 (b) | | $56,618 | 5 |
| 6 | 565 | Transmission - PPFAC Eligible | $ 4,511 (a) | | | $4,511 | 6 |
| 7 | | Base Cost | $ 307,526 | $ 49,561 | $ (15,088) | $ 341,998 | 7 |
| 8 | | Net Base FFPAC Eligible Costs | $ 307,526 | $ (23,878) | $ (15,088) | $ 268,559 | 8 |
| 9 | | Adjusted Retail Sales , GWh | 9,319 (a) | 9,319 | 9,319 | 9,319 | 9 |
| 10 | | Base Fuel Cost per KWh (¢/kWh) | 3.30 | (0.26) | (0.16) | $\boxed{2.88}$ | 10 |

**Supporting Schedules**
(a) TEP Exhibit DGH-8
(b) AECC Exhbit KCH-1, p. 3

# BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT

AECC-2

admitted

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA | ) | Docket No. E-01933A-07-0402 |
| IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103 | ) | Docket No. E-01933A-05-0650 |

**Direct Testimony of Kevin C. Higgins**

**on behalf of**

**Phelps Dodge Mining Company and**

**Arizonans for Electric Choice and Competition**

**Rate Design**

**March 14, 2008**

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## DIRECT TESTIMONY OF KEVIN C. HIGGINS

### I. Introduction

**Q. Please state your name and business address.**

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

**Q. By whom are you employed and in what capacity?**

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

**Q. Are you the same Kevin C. Higgins who filed direct testimony in the revenue requirement phase of this proceeding on behalf of Phelps Dodge Mining Company ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC")?**

A. Yes, I am.

### II. Overview and Conclusions

**Q. What is the purpose of your testimony in this phase of the proceeding?**

A. My testimony addresses several cost-of-service and rate design issues in TEP's general rate case filing, and recommends changes to TEP's proposed rate design in support of a just and reasonable outcome. My testimony in this phase of the proceeding is directed to TEP's "Cost-of-Service Methodology."

**Q. Please summarize your conclusions and recommendations with respect to rate design issues in this proceeding.**

A. I offer the following conclusions and recommendations:

(1) In my revenue requirement testimony I concluded that TEP's proposed Termination Cost Regulatory Asset Charge ("TCRAC") is without merit and recommended that it should be rejected. Consistent with this recommendation, no TCRAC should be adopted. However, if the Commission does not accept my recommendation to reject the TCRAC, then the cents-per-kWh rate design proposed by TEP for the TCRAC should be rejected, and instead, the costs should be recovered through an equal-percentage-of-bill rider applied to all retail customers.

(2) I recommend that the Commission reject the Peak and Average Demand method that TEP proposes for the allocation of generation plant costs, as it is a conceptually-flawed approach. This method double counts average demand, resulting in a bias against higher-load-factor customers. This problem can be remedied by using the Average and Excess Demand method, which uses the same energy-based allocation that TEP is recommending for generation costs, but avoids the double-counting of average demand during the system peak.

(3) Multiple cost-of-service studies show that the General Service class is significantly over-recovering its costs under current rates (inclusive of the Fixed CTC).

(4) Both the Average and Excess Demand method and the 4CP method show the Large Light & Power class dramatically over-recovering its costs at current rates (inclusive of the Fixed CTC).

(5) TEP's use of Peak and Average Demand method for allocating transmission expense should be rejected. The FERC-approved transmission rates that TEP is charging itself for providing service to its retail customers were determined in the first instance using the 4CP method. The same 4CP method should be used for allocating transmission expense across customer classes. I recommend that the Commission order TEP to re-file its unbundled transmission rates such that: (a) transmission expense is allocated to customer classes on a 4CP basis; and (b) transmission rates for demand-billed customers are recovered solely through a demand charge, not an energy charge.

(6) TEP's distribution cost-of-service study shows that the distribution system costs attributable to the Large, Light and Power class at TEP's requested rate of return is a little over $4 million. Yet, the unbundled distribution <u>charges</u> TEP is proposing for these customers would recover $26.6 million – over 6.5

times the cost of providing distribution service to them. The distribution charges for this customer class should be dramatically reduced to better reflect the actual cost to provide this service.

(7) I recommend that the first $30 million of any revenue reductions ordered by the Commission (relative to the $63 million base rate increase being proposed by TEP) should be apportioned as follows: (a) $20 million reduction to the General Service class in recognition that this class is over-recovering costs under <u>current</u> rates; and (b) $10 million reduction to Large, Light & Power to be effected through a reduction in the unbundled distribution charge to these customers to bring these charges closer to distribution cost-of-service. If the Commission orders less than a $30 million reduction from the $63 million increase requested by TEP, then the dollar reduction should be apportioned between General Service and Large, Light & Power in this same 2:1 ratio.

(8) If the Commission orders a rate reduction that is greater than $30 million (relative to the $63 million base rate increase being proposed by TEP) then I recommend that the incremental reduction be apportioned to each customer class on an equal percentage basis (except Mines, which are presumed to be served under special contracts). In the case of Large, Light & Power, the reduction should be targeted to the unbundled distribution charge.

(9) If the Commission approves a base rate increase that is greater than $63 million, then I recommend that any incremental increase above $63 million should be apportioned to General Service and Large, Light & Power such that the incremental percentage rate increase to these classes is 50 percent of the overall retail percentage increase.

(10) I support TEP's overall move toward time-of-use rates, as this will improve price signals to customers.

(11) TEP's proposed rate design for non-residential customers is severely skewed toward energy charges and away from demand charges. For each demand-billed rate schedule, TEP should be ordered to reformulate the distribution charge such that 100 percent of the distribution rate is recovered either in the customer charge or the demand charge – with none of the recovery occurring in an energy charge. Similarly, for rate schedules that are demand-billed, a minimum of 55 percent of TEP's generation cost that is unrelated to fuel and purchased power should be recovered through a demand charge (and removed from the energy charge).

(12) TEP should be required to file an interruptible rate schedule that provides a range of options with respect to notice requirements, duration, and frequency, and which provides a credit to participating customers based on the value of the capacity expense the customer allows the utility to avoid. The

interruptible rate schedule should be developed after consultation with Staff and interested stakeholders in a collaborative process.

(13) TEP's proposal for inverted block rates for small General Service customers is misguided and should be rejected. The notion of "lifeline" rates does not translate to non-residential customers. The relative differences in electricity usage among commercial (and industrial customers) are driven largely by the differing requirements of their respective businesses, as opposed to individual consumption preferences. Applying inverted block pricing to non-residential customers simply creates a new subsidy in which the larger customers on the rate schedule pay for the energy costs of the smaller customers on the rate schedule – e.g., the grocery stores pay for the energy costs of the gas stations – without regard to the energy efficiency practices of either.

## III. <u>Termination Cost Regulatory Asset Charge</u>

**Q. What is the Termination Cost Regulatory Asset Charge?**

A. As discussed in my revenue requirements testimony, the Termination Cost Regulatory Asset Charge ("TCRAC") is the mechanism that TEP has proposed for recovering the $788 million regulatory asset it has requested if the Cost-of-Service Methodology is adopted. TEP asserts that such a regulatory asset is necessary "in recognition of the economic burden imposed on TEP as a result of the extended rate freeze and return to full cost-of-service regulation."[1] The first year cost to TEP customers of the TCRAC would be $117.6 million.

In my revenue requirements testimony I explain why the TCRAC proposal is without merit and recommend that it be rejected.

**Q. What rate design has TEP proposed for the TCRAC?**

A. TEP has proposed a straight kilowatt-hour charge of 1.2622 cents/kWh applicable to all retail kilowatt-hours.

[1] Direct testimony of Kentton C. Grant, p. 2, lines 22-25.

**Q. If notwithstanding your recommendation that the TCRAC be rejected, some form of the mechanism is approved by the Commission, do you believe TEP's proposed rate design should be adopted?**

A. Absolutely not. TEP is attempting to recover "foregone rate increases" due to the rate cap. A straight kilowatt-hour charge is entirely inappropriate for such a purpose. There is no basis to assert that any rate increases that TEP might have "foregone" between 2003 and 2008 would have been recovered from customers on a straight kilowatt-hour basis. In fact, the likelihood of recovering a general rate increase in such a manner is almost nil. Recovering such an extraordinary cost on a straight kilowatt-hour basis would ignore relative cost-of-service among rate classes and would unfairly burden higher-load-factor customers within rate classes.

**Q. If notwithstanding your recommendation that the TCRAC be rejected, some form of the mechanism is approved by the Commission, what rate design would be most appropriate?**

A. If TEP is permitted some type of regulatory asset recovery such as the TCRAC in exchange for applying the Cost-of-Service Methodology to post-2008 rates, then the most reasonable mechanism for cost recovery from customers would be an equal <u>percentage</u> of bill rider applied to all retail customers. Such a mechanism would assess the regulatory asset burden such that it was directly proportionate to the rates that are decided in this proceeding. That is the most reasonable means for assigning responsibility for recovering any "foregone" rate increases from the past.

## IV. Class Cost-of-Service

**Q. What is the purpose of cost-of-service analysis?**

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- Separating the utility's costs in accordance with the various *functions* of its system (e.g., generation, [or production], transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for causing the utility's costs to the various customer classes.

**Q. What is the role of cost-of-service analysis in setting rates?**

A. Each of the three steps above has an important role in the ratemaking process. If rates are unbundled by function, as they are in Arizona, then separating the utility's costs by function is important in determining which costs are generation-related, transmission-related, and distribution-related.

The classification of costs is critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes is important for determining revenue apportionment across customer classes, also called "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. For these reasons, the results of the class cost-of-service analysis should be given very strong weighting in guiding the proper revenue apportionment.

### A. <u>Allocation of Generation Plant Costs</u>

**Q. What approach has TEP used for allocating generation plant costs between TEP retail customers and FERC-jurisdictional customers?**

A. As explained in the direct testimony of TEP witness D. Bentley Erdwurm, TEP uses the 4-Coincident Peaks ("4CP") method for allocating generation plant costs between its state and federal jurisdictional loads. TEP's system is designed to meet peak demands in the months of June, July, August, and September. Consequently, the allocation factor for generation capacity is calculated using each jurisdiction's contribution to system peak at the time of the June, July, August, and September peaks.

**Q. In your opinion, is the 4CP method appropriate for allocating TEP's generation plant costs?**

A. Yes, given the characteristics of TEP's system, the 4CP method is appropriate for allocating generation plant costs. As noted by Mr. Erdwurm, the 4CP method has been accepted by FERC for application to TEP.

**Q. Does TEP also use the 4CP method for allocating generation plant costs across its retail customer classes?**

A. No. Even though TEP uses the 4CP method for allocating generation plant costs between its jurisdictions, TEP does not use this method for allocating costs across its retail customer classes. For class cost of service, TEP uses a variant of the "Peak and Average Demand" method, which Mr. Erdwurm refers to as "Average and Peaks". [2]

**Q. Are you familiar with the Peak and Average Demand method?**

A. Yes. The Peak and Average Demand method is classified in the NARUC Cost Allocation Manual as a "Judgmental Energy Weighting" approach. According to this method, fixed production cost is allocated based on a combination of each class's share of coincident peak demand, as well as each class's share of energy usage. In applying this method, class energy consumption is typically expressed as "average demand," which gives rise to the term "Peak and Average." (Average demand is simply annual energy divided by the number of hours in the year.)

**Q. In your opinion, is the Peak and Average Demand method appropriate for allocating TEP's generation plant costs?**

A. No. The Peak and Average Demand method is conceptually flawed in that average demand is already included in peak demand and is thus counted twice in the allocation of costs. This double-counting contributes to a bias against higher-load-factor customers inherent in this method. Fortunately, however, this problem

[2] "Peak and Average Demand" is the nomenclature used in the NARUC Electric Utility Cost Allocation Manual.

can be remedied by applying an alternate method that uses the same energy-based allocation that TEP is recommending, but avoids the double-counting of average demand at peak. This alternative is known as the "Average and Excess Demand" method.

**Q. Before discussing this alternative approach, please explain the analytical flaw in the Peak and Average Demand method.**

A. We can use a simple example to illustrate the Peak and Average Demand method and its serious flaw. Assume we have two customer classes: Flat and Peaky. To highlight the underlying drivers of the Peak and Average Demand method, let us assume that the Flat class has a constant load of 500 MW throughout the year. Let us further assume that the load pattern of the Peaky class is as follows: January-March: 300 MW; April-May: 500 MW; June: 700 MW; July-August: 800 MW; September: 700 MW; October: 500 MW; and December: 300 MW. This example is illustrated in Figure KCH-2, on the following page.

## Figure KCH-2

## Peak and Average Demand Method: Illustrative Example

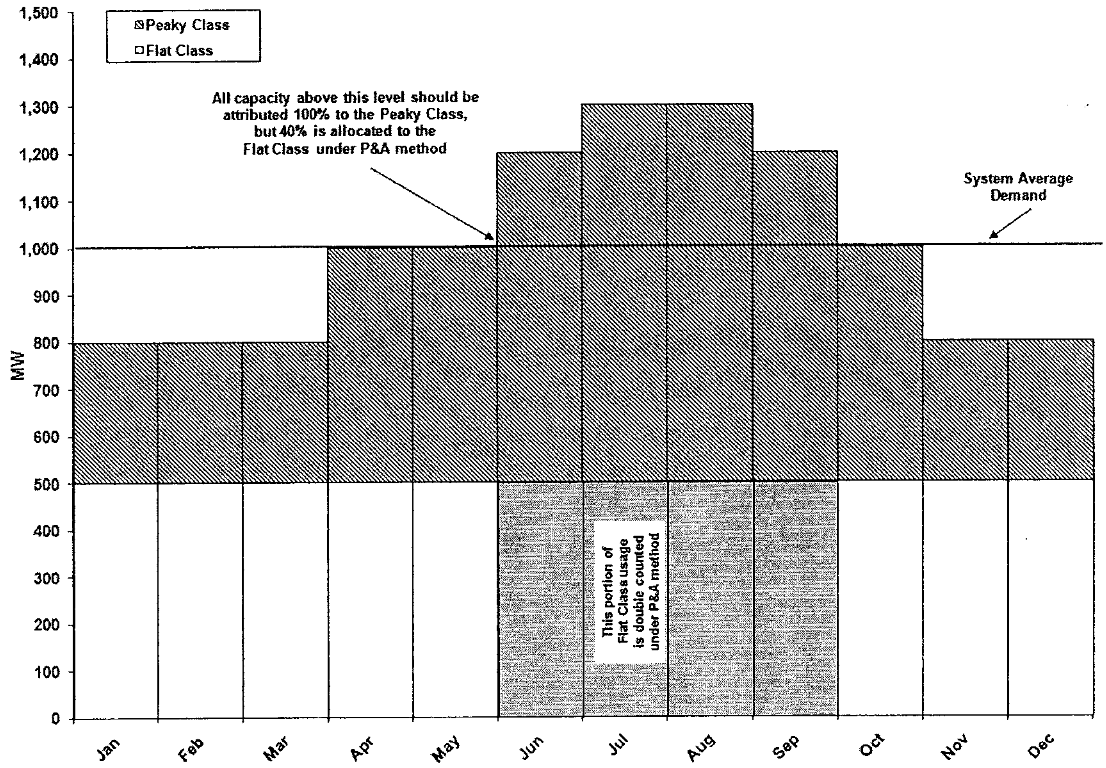


Figure KCH-2 shows the monthly demand of the Flat class at the bottom of the diagram. The monthly demand of the Peaky class is stacked on top of the Flat class's demand, such that the sum of the two constitutes the total demand for the system. The average demand of each of these classes is 500 MW, resulting in an average demand for this two-class system of 1000 MW. Accordingly, the Peak and Average Demand method will allocate each of these classes 50 percent of the responsibility for the energy, or average demand, portion of costs.

The system peak demand averages 1250 MW in the four summer months, June through September. It is clear in this example that all of the incremental capacity required above the system average of 1000 MW demand is attributable to the needs of the Peaky class – after all, the load of the Flat class is, of course, flat. But the Peak and Average Demand method will not allocate the full cost of this incremental capacity to the Peaky class. Instead, it will allocate these incremental costs in accordance with the share of each class's demand during the peak summer months; that is, the Flat class will be allocated 40% of the incremental cost (500 MW/1250 MW) and the Peaky class will be allocated 60% of the incremental cost. Put another way, even though all of the Flat class's usage during the summer has already been accounted for in the allocation of average demand, the Flat class will be allocated an additional 40% of the costs of the incremental capacity above system average demand when the summer peak demand is apportioned. This additional allocation occurs because the Peak and Average Demand method allocates capacity costs based on total demand during the summer – not just the excess above average demand, even though average demand has already been fully allocated in the first step. This additional allocation is the double-weighting to which I referred previously in my testimony. In my opinion, this double-weighting amounts to a serious analytical flaw in the Peak and Average Demand method.

**Q. Has the Commission expressed concern about the use of the Peak and Average Demand method?**

A. Yes. In Decision No. 69663 issued June 28, 2007, the Commission addressed Staff's recommended use of the Peak and Average Demand method in the Arizona Public Service Company ("APS") rate case. APS had used the 4CP method. The Commission stated:

> We agree with Staff that an energy-weighting method for allocating production plant is appropriate for APS. However, we are not convinced that the method recommended by Staff is the method that should be adopted. AECC's recommended Average and Excess Demand method would eliminate the criticism that the average demand is being counted twice. [Decision No. 69663, p. 70, line 27 – p. 71, line 2.]

**Q. Does the Average and Excess Demand method avoid the double-weighting of average demand costs?**

A. Yes. The Average and Excess Demand method avoids the problem of double-weighting while using the same allocation treatment of energy, or average demand, as the Peak and Average Demand method: the difference is in the treatment of the incremental capacity requirements above average demand.

The Average and Excess Demand method is described in the NARUC Manual in its section entitled "Energy Weighting Methods." This method has the virtue of meeting the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[3] At the same time, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

**Q. How does the Average and Excess Demand method apportion responsibility for incremental production plant that is required to meet loads that are above average demand?**

A. The Average and Excess Demand method allocates the cost of capacity above average demand in proportion to each class's excess demand, where excess demand is measured as the difference between each class's individual peak demand[4] and its average demand. By focusing on excess demand, this method avoids the double-weighting of average demand that occurs in the Peak and Average Demand method.

**Q. How would the Average and Excess Demand method allocate the capacity above average demand in your illustrative example?**

A. The capacity above average demand would be allocated in proportion to each class's share of excess demand. In this example, the peak demand of the Flat class is the same as its average demand; that is, its excess demand is zero. The peak for the Peaky class is 800 MW, which translates into a class excess demand of 300 MW (i.e., 800 MW - 500 MW), which, of course, is also the entirety of the excess demand on this system. Thus, the Peaky class is allocated all of the cost associated with incremental capacity above average demand. Put another way, the Average and Excess Demand method properly assigns the cost of the incremental amount of production plant used to serve system requirements above average demand.

**Q. Is the Average and Excess Demand method used elsewhere in this region of the country?**

A. Yes. This method is used by both Salt River Project and Public Service Company of Colorado.

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[3] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

**Q. Has TEP prepared a class cost-of-service analysis using the Average and Excess Demand method?**

A. Yes. TEP prepared a class cost-of-service study using the Average and Excess Demand method in response to DOD Data Request 6.1.

**Q. Has TEP also prepared a class cost-of-service analysis using the 4CP method?**

A. Yes. TEP prepared a class cost-of-service study using the 4CP method in response to DOD Data Request 3.3 (Update).

**Q. Do you have any observations concerning the various cost-of-service analyses prepared by TEP?**

A. Yes. Each of the cost-of-service studies performed by TEP shows the rates-of-return by customer class assuming that there are no Fixed CTC revenues (or DSM-related revenues) being recovered in current rates. For example, TEP's Schedule G-1, which summarizes the Company's Peak and Average Demand cost-of-service study, shows Total TEP operating income of negative $13.2 million. It also shows negative returns for each rate class except General Service and Lighting. These negative returns are only appearing in Schedule G-1 because TEP removed $89.6 million in Fixed CTC revenues from rates for this analysis. But of course, customers are still paying these charges, so the rates of return that appear in Schedule G-1 – or any of TEP's cost-of-service studies – are not very helpful upon first review. To be analytically useful, the Fixed CTC revenues (and

[4] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

DSM-related revenues) must be restored and attributed to the classes that are currently paying these revenues.

**Q. Have you reconstructed TEP's cost-of-service results with the Fixed CTC revenues included in current rates?**

A. Yes. For TEP's Peak and Average Demand study (Schedule G-1), the results are reconstructed in Schedule KCH-7, page 1. This schedule shows a Total TEP operating income of $44.3 million. The class rates of return appearing in line 25 should be interpreted as the returns derived using TEP's Peak and Average Demand study with the Fixed CTC and DSM revenues <u>in</u> current rates.

**Q. Do you have any other observations concerning TEP's cost-of-service results?**

A. Yes. Apparently TEP conducted its class cost-of-service study for a different test period than was used for revenue requirement. The test period for class cost-of-service is the year ending June 30, 2006, whereas the test period for revenue requirement is for the year ending December 31, 2006.

**Q. Does the use of the test period ending June 30, 2006 instead of December 31, 2006 have much impact on the study results?**

A. Apparently, yes. In TEP's Response to DOD Data Request 3.2, TEP reran its Peak and Average Demand study for the test period that coincides with the test period used for revenue requirement – the year ending December 31, 2006. In Schedule KCH-7, page 2, I have reconstructed TEP's results with Fixed CTC revenues (plus DSM-related revenues) included in current rates. The results show that the rate of return for the Large Light & Power class is considerably higher using the test period ending December 31, 2006 than for the test period ending June 30, 2006.

**Q. Do you have any other observations concerning TEP's cost-of-service results?**

A. The results for the Mines class need to be viewed with some caution. TEP's cost-of-service study shows this class as under-recovering, but current revenues for this class do not reflect the rate changes for mining customers that will be in effect in 2009. In Decision No. 69873, issued August 28, 2007, the Commission approved a new special contract for one major mining customer, the pricing terms of which are confidential. The special contract for the other mining customer expires at the end of 2008 and this customer's rates in the rate effective period will undoubtedly be different than those reflected in TEP's cost-of-service studies. Any increased revenues that TEP will receive from charging higher rates to customers in the Mines class in the rate effective period will contribute to the recovery of TEP's target revenue requirement. TEP's filing does not currently reflect these additional revenues.

**Q. Have you reconstructed TEP's cost-of-service results for the Average and Excess Demand and 4CP methods with the Fixed CTC revenues included in current rates?**

A. Yes. These results are shown in Schedule KCH-7, pages 3 and 4. Table KCH-1, below, summarizes the class rates of return that appear in Schedule KCH-7.

**Table KCH-1**

**Class Rates of Return Using Different CCOS Methods**
(Fixed CTC included in current revenues)

| CCOS Method | Total | Res | GS | LL&P | Mines | Lighting | Pub Auth |
|---|---|---|---|---|---|---|---|
| Peak & Average (6/06) | 4.50% | 1.12% | 13.88% | -2.84% | -25.68% | 3.22% | -2.03% |
| Peak & Average (12/06) | 4.50% | 0.23% | 14.11% | 6.18% | -22.03% | 6.94% | -11.83% |
| Average & Excess Dem. | 4.50% | -2.15% | 13.26% | 20.20% | 4.08% | -9.27% | 6.51% |
| 4 CP | 4.50% | -1.82% | 13.04% | 26.33% | 6.90% | 13.36% | -16.70% |

**Q. What observations do you draw from the results of the Average and Excess Demand and 4CP methods?**

A. Both the Average and Excess Demand method and the 4CP method show the Large Light & Power class dramatically over-recovering its costs at current rates (inclusive of the Fixed CTC).

**Q. Do you have any observations concerning the study results for the General Service class?**

A. Yes. Each cost-of-service study shows that the General Service class is significantly over-recovering its costs under current rates (inclusive of the Fixed CTC).

**Q. What conclusions do you draw concerning the use of these cost-of-service results for the determination of rate spread in this proceeding?**

A. There are at least two key insights that stand out from these results. First, any rate spread should recognize that the General Service class is already paying rates that are too high even if TEP received the full $63 million rate increase it is requesting under the Cost-of-Service Methodology (not counting the TCRAC). Secondly, under the more commonly-utilized CP and Average and Excess

Demand cost allocation methods, the Large Light & Power class is significantly over-recovering. I will present additional information on this issue when I discuss distribution cost-of-service later in this Section IV.

I will present my overall rate spread recommendations in Section V of my testimony.

**B. <u>Allocation of Transmission Expense and Transmission Rate Design</u>**

**Q. What has TEP proposed with respect to the allocation of transmission expense?**

A. Transmission expense is an unbundled rate component in TEP's tariff. TEP has proposed that transmission expense be allocated to customer classes using the same Peak and Average Demand method the Company uses for allocating generation plant costs.

**Q. What is your assessment of TEP's approach to allocating transmission expense?**

A. As I explained above, the use of the Peak and Average Demand method for allocating generation plant costs is highly flawed. The method is even more inappropriate for allocating transmission expense, as there is no transmission equivalent to base load generation plant to justify the use of Average Demand as an allocator. The use of Peak and Average Demand method for allocating transmission expense should be soundly rejected.

The FERC-approved transmission rates that TEP is charging itself for providing service to its retail customers were determined in the first instance using the 4CP method. The same 4CP method should be used for allocating transmission expense across customer classes.

**Q. Have you performed an allocation of transmission expense using the 4CP method?**

A. Yes, I have. This analysis is presented in Schedule KCH-8.

**Q. Do you have any other comments concerning transmission rates?**

A. Yes. TEP is proposing to recover transmission expense on a cents-per-kWh basis. Such a rate design for transmission service is entirely inappropriate for demand-metered customers. Transmission service is inherently capacity-related and transmission rates should be designed on a dollars-per-kW of monthly demand basis, which is how TEP's FERC-approved transmission rates are designed. Failure to design transmission rates on a demand-billed basis will unfairly shift transmission costs <u>within</u> demand-billed rate schedules from lower-load-factor customers (whose use of the transmission system is relatively "peaky") to higher-load-factor customers (whose use of the transmission system is relatively constant).

In Schedule KCH-8, I present re-designed transmission rates by customer class using TEP's proposed transmission expense.

**Q. What transmission rate design is utilized by APS?**

A. This issue was addressed in the most recent APS rate case. As a result of that proceeding, APS changed its transmission rate design from a cents-per-kWh charge to a dollars-per-kW-month charge for demand-billed customers, just as I am recommending here.

**Q. Please summarize your recommendations concerning transmission cost allocation and rate design.**

A. I recommend that the Commission order TEP to re-file its unbundled transmission rates such that: (1) transmission expense is allocated to customer classes on a 4CP basis; and (2) transmission rates for demand-billed customers are collected solely through a demand charge, not an energy charge.

### C. Allocation and Recovery of Distribution Costs for Large, Light & Power

**Q. What is the function of the utility's distribution system?**

A. The distribution system delivers power from the high-voltage transmission system to the customer's meter.

**Q. Are there issues concerning the allocation of distribution costs that you wish to discuss?**

A. Yes. TEP's distribution cost-of-service study shows that the distribution system costs attributable to the Large, Light and Power class at TEP's requested rate of return is slightly more than $4 million.[5] Distribution costs for these customers are relatively modest, since they take service at 46,000 volts or greater, and therefore do not use the lower-voltage portion of the distribution system.

Yet, the unbundled distribution <u>charges</u> being levied on these customers is <u>orders of magnitude</u> greater than the cost to provide distribution service to these customers. As shown in Exhibit KCH-9, TEP's proposed distribution rates would

[5] TEP Schedule G-6 (Unit Costs), page 1, column 4, line 11.

recover $26.6 million from these customers – over 6.5 times the cost of providing distribution service to them. These charges are way out of line, and are well above what utilities typically charge high-voltage customers for distribution service.

**Q. What do you recommend with respect to the distribution charges for the Large, Light and Power class?**

A. The distribution charges for the Large, Light and Power customers should be dramatically reduced to better reflect the actual cost to provide this service. I will make a specific recommendation in this regard in the rate spread portion of my testimony which follows in Section V.

## V. Rate Spread

**Q. What general guidelines should be employed in spreading any change in rates?**

A. In determining rate spread, or revenue apportionment, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

**Q. What rate spread has TEP recommended for its Cost-of-Service Methodology?**

A. TEP's proposed rate spread is shown in Table KCH-2, below. This table shows TEP's recommended rate spread both with and without the Company's proposed TCRAC. In both cases, the rate changes are measured from the baseline that includes the Fixed CTC and DSM-related revenues in current rates.

**Table KCH-2**

**TEP's Proposed Rate Spread**
Cost-of-Service Methodology

| Customer Class | Base Rate Increase[6] | | Increase w/ TCRAC[7] | |
|---|---|---|---|---|
| | $000 | % | $000 | % |
| Residential | $34,862 | 9.90% | $83,638 | 23.75% |
| General Service | $20,843 | 6.92% | $62,677 | 20.81% |
| LL&P | $ 5,057 | 7.46% | $17,035 | 25.14% |
| Mines | $ 0 | 0.00%[8] | $11,674 | 26.70% |
| Lighting | $ 130 | 2.36% | $ 648 | 11.72% |
| Public Authorities | $ 2,199 | 13.55% | $ 5,042 | 31.06% |
| Total Retail | $63,091 | 8.02% | $180,714 | 22.98% |

**Q. What are your recommendations concerning rate spread?**

A. Let me start with the Company's TCRAC proposal. As I discussed above, I recommend that the TCRAC proposal be rejected. However, if some portion of the TCRAC is adopted then it should be spread to customer classes on an equal percentage of bill rider applied to all retail customers.

[6] Source: TEP Schedule H-1
[7] Source: TEP Schedule H-1 TRCAC
[8] See previous discussion on Mines class in Section IV.C of this testimony.

Turning to base rates, there is strong evidence in this proceeding that base rates should be reduced from their current levels; consequently, I do not expect the 8.02% base rate increase proposed by TEP to prevail. Therefore, my rate spread recommendation with respect to base rates addresses how best to implement any reductions from the $63 million base rate increase being requested by TEP.

**Q. Please proceed.**

A. I recommend that the first $30 million of any reductions ordered by the Commission relative to the $63 million base rate increase being proposed by TEP should be apportioned as follows: (1) $20 million reduction to the General Service class in recognition that this class is over-recovering costs under <u>current</u> rates; and (2) $10 million reduction to Large, Light & Power to be effected through a reduction in the unbundled distribution charge to these customers to bring these charges closer to distribution cost-of-service. If the Commission orders less than a $30 million reduction from the $63 million increase requested by TEP, then the dollar reduction should be apportioned between General Service and Large, Light & Power in this same 2:1 ratio.

If the Commission orders a rate reduction that is greater than $30 million (relative to the $63 million base rate increase being proposed by TEP) then I recommend that the incremental reduction be apportioned to each customer class on an equal percentage basis (except Mines, which are presumed to be served under special contracts). In the case of Large, Light & Power, the reduction should be targeted to the unbundled distribution charge.

**Q. Can you provide a simple example of how this rate spread approach would work?**

A. Yes. I have prepared an example in Schedule KCH-10 that assumes the Commission reduces TEP's $63 million base rate increase by $63 million – effectively holding overall revenues constant.

In this example, the first $30 million of the reduction is apportioned between General Service and Large, Light & Power as described above. The remaining $33 million reduction is apportioned to each customer class (except Mines) on an equal percentage basis. Thus, each customer class (except Mines) would experience a 4.46 percent revenue reduction in addition to any reduction awarded as part of the first $30 million reduction.

**Q. What do you recommend if base rates are increased in an amount greater than the $63 million requested by TEP?**

A While I do not believe this scenario is likely, it is technically possible as TEP has not yet updated the fuel and purchased power portion of its revenue requirement. If the Commission approves a base rate increase that is greater than $63 million, then I recommend that any incremental increase above $63 million should be apportioned to General Service and Large, Light & Power such that the incremental percentage rate increase to these classes is 50 percent of the overall retail percentage increase. This apportionment is in recognition of the cost-of-service issues discussed above.

## VI. Rate Design

**Q. What is your overall assessment of TEP's proposed rate design?**

A. I support TEP's overall move toward time-of-use ("TOU") rates. TOU rates improve price signals to customers. At the same time, there are serious problems with TEP's proposed rate design for non-residential customers: namely, TEP is placing far too much of its cost recovery in energy charges and not enough in demand charges. The result is to create an unfair burden on higher-load-factor customers. I also believe that TEP's tariff is lacking in that it does not provide an option for interruptible rates. Interruptible rates provide a valuable tool for utilities in meeting system demand and can be a valuable pricing option to customers as well. Finally, I believe that TEP's proposal for inverted block rates for small General Service customers is misguided and should be rejected.

**Q. Please proceed. Why do you support TEP's move toward greater applicability of TOU rates?**

A. Energy costs vary across the hours of the day, with the most expensive hours typically occurring from the afternoon to the evening in summer. Designing the energy price to end-use customers to reflect variations in energy costs sends the proper signal to customers regarding the relative cost to operate the system during the peak, shoulder, and off-peak hours. Customers would then use this pricing information to alter their discretionary patterns of usage, increasing efficiency and lowering the overall cost of energy to the system.

**Q. Are there other reasons besides economic efficiency to make TOU rates more widely available to customers?**

A. Yes. In addition to providing these customers with an incentive to better respond to price signals, TOU rates will ensure that these customers pay rates that are more closely aligned with the costs they cause. Basic fairness dictates that customers whose patterns of energy consumption are less expensive to serve because of their load pattern should see that lower cost reflected in their bills.

**Q. Does the Energy Policy Act of 2005 require utilities to expand the availability of TOU rates?**

A. Yes. Section 1252 of the Act contains a passage that states as follows:

> Not later than 18 months after the date of the enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.[9]

The increased application of TOU rates in TEP's service territory helps to address these requirements.

**Q. Turning now to the issue of TEP's demand and energy charges, please explain your concerns.**

A. Demand-related costs are those costs that are incurred by a utility to meet customer peak, customer-class-peak and/or system peak requirements. All but the smallest of non-residential customers are billed both for the demand they require (maximum load in the billing cycle) and the energy they consume (kilowatt-hours of consumption).

TEP's proposed rate design is severely skewed toward energy charges and away from demand charges. For example, TEP is proposing to recover a significant portion of its distribution costs through energy charges. For customers who are billed on a demand-basis, this design is entirely inappropriate. Distribution costs are customer-related and demand-related – they are not energy-related. There is a strong consensus on this point. For example, in discussing distribution cost of service, the NARUC Cost Allocation Manual states: "...[A]ll costs of service can be identified as energy-related, demand-related, or customer-related. <u>Because there is no energy component of distribution-related costs, we need to consider only the demand and customer components</u>." [10] [Emphasis added]

**Q. From a customer's perspective, why should it matter if TEP proposes a rate design that does not fully recover its demand-related <u>costs</u> through demand-related <u>charges</u>?**

A. If a utility proposes demand-related charges that are below the cost of demand, it is going to seek to recover its class revenue requirement by over-recovering its costs in another area, most typically through levying an energy charge that is above unit energy costs, which is the case here. For a given rate schedule, when demand-related charges are set below demand-related cost, and the energy charges are set above energy cost, those customers with relatively-

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[9] Energy Policy Act of 2005, Sec. 1252. I note that this section also requires state regulatory authorities to conduct an investigation and issue a decision as to whether it is appropriate to implement these and other standards in the Act.
[10] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 89.

higher load factors are forced to subsidize the costs of the lower-load-factor customers within the rate class.

**Q. Why is it important for rate design to be representative of underlying cost causation?**

A. Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals. For example, setting demand-related charges below the cost of demand understates the economic cost of demand-related assets, which in turn distorts consumption decisions, and calls forth a greater level of investment in fixed assets than is economically desirable.

At the same time, aligning rate design with underlying cost causation is important for ensuring equity among customers, because properly aligning charges with costs minimizes cross-subsidies among customers. As I stated above, if demand costs are understated in utility rates, the costs are made up elsewhere – typically in energy rates. When this happens, higher-load-factor customers (who use fixed assets relatively efficiently through relatively constant energy usage) are forced to pay the demand-related costs of lower-load-factor customers through the energy charge. This amounts to a cross-subsidy that is fundamentally inequitable.

**Q. What do you recommend with respect to the rate design of TEP's distribution charges?**

A. For each demand-billed rate schedule, TEP should be ordered to reformulate the distribution charge such that 100 percent of the distribution rate is recovered either in the customer charge or the demand charge – with none of the recovery occurring in an energy charge. Further, in so doing, none of the energy charges removed from the distribution rate should be shifted to other unbundled components.

**Q. Do you have any additional comments with respect to TEP's treatment of demand and energy charges?**

A. Yes. My criticism of TEP's skewing of its rate design toward energy is also applicable to TEP's proposed transmission and generation rates. My recommendation with respect to transmission rate design was discussed in Section IV.B, above. In the case of generation rates, TEP proposes <u>no</u> demand charge to recover costs associated with generation capacity, and instead proposes to recover all of its generation-related costs through energy charges. While recovery of costs through an energy charge is entirely appropriate for fuel and purchased power costs, it is <u>not</u> appropriate for capacity or demand-related costs.

**Q. What portion of TEP's generation cost that is unrelated to fuel and purchased power should be recovered in a demand charge?**

A. Arguably, <u>all</u> of TEP's generation cost that is unrelated to fuel and purchased power costs should be recovered through a demand charge from those customers who are demand-billed. At a <u>minimum</u>, for rate schedules that are demand-billed, 55 percent of TEP's generation cost that is unrelated to fuel and purchased power should be recovered through a demand charge (and removed from the energy charge). This percentage represents the portion of TEP's generation-related demand expense that TEP allocates on a coincident-peak basis in its cost-of-service study.

**Q. What do you recommend with respect to the rate design of TEP's generation charges?**

A. For each demand-billed rate schedule, TEP should be ordered to reformulate the generation charge such that at least 55 percent of the generation rate unrelated to fuel and purchased power is recovered in the demand charge. Further, in so doing, none of the energy charges removed from the generation rate should be shifted to other unbundled components.

**Q. Turning now to the issue of interruptible rates, what recommendation do you make to the Commission?**

A. In my opinion, TEP's tariff is lacking in that it does not provide an interruptible rate schedule option. A well-designed program that offers an interruptible rate schedule can allow the utility to meet its peaking needs and/or operating reserve requirements in a manner that provides benefits to participating and non-participating customers by reducing the overall cost of capacity to the utility. Customers choosing interruptible service should receive a credit based on the value of the capacity expense they allow the utility to avoid. The credit would be commensurate with the terms under which the customer agrees to be interrupted, e.g., length of advance notice required, duration, and frequency. A well-designed program would provide a menu of options that would allow the customer to select from among several combinations of terms.

**Q. How should an interruptible credit be valued?**

A. As I stated, the value of the credit would depend on the terms of interruption. A potential benchmark for measuring interruption value is the $7.00

per kW-month market-based capacity charge that TEP is proposing for its Luna Energy Facility.

**Q. What is your recommendation to the Commission on interruptible rates?**

A. TEP should be required to file an interruptible rate schedule that provides a range of options with respect to notice requirements, duration, and frequency, and which provides a credit to participating customers based on the value of the capacity expense the customer allows the utility to avoid. The interruptible rate schedule should be developed after consultation with Staff and interested stakeholders in a collaborative process.

**Q. Turning now to the issue of inverted block rates for small General Service customers, what has TEP proposed in that regard?**

A. TEP has proposed inverted block rates for small General Service customers, i.e., customers taking service on Schedules GS-10 and GS-76N. With inverted block rates, energy charges increase as energy usage increases.

**Q. What is your assessment of inverted block rates for non-residential customers?**

A. Inverted block rates for non-residential customers is a misguided notion and entirely inappropriate. This proposal should be rejected.

**Q. Please explain.**

A. The premise behind inverted block rates is that it is important to send a price signal to customers that increasing energy usage is costly to the utility system. This concept is then paired with the notion that there is a critical minimum amount of electric power that is necessary to meet basic needs. The rate design that results from combining these ideas is one in which the initial pricing block (corresponding to the first energy used in the billing period) is priced at a relatively low rate, whereas energy consumption above this amount is priced at higher rates. For small General Service customers, TEP proposes three progressively-increasing pricing blocks.

The notion of a critical minimum or a "lifeline" amount of electric power (that is priced at a lower rate) is grounded in a value judgment about what portion of electric power consumption for a residential customer is for "necessities" (e.g., lighting) and what portion constitutes discretionary or even luxury usage (e.g., heating a hot tub) . As varied as households may be, they are more homogeneous than businesses, and I believe it is reasonable to establish prices for residential customers that distinguish between "lifeline" power consumption and discretionary or luxury usage. Consequently, inverted block rates are appropriate for residential customers.

However, the notion of "lifeline" rates does not translate to non-residential customers. The relative differences in electricity usage among commercial (and industrial customers) are driven largely by the differing requirements of their respective businesses, as opposed to individual consumption preferences. A grocery store might be pursuing vigorous energy efficiency measures, but still be consuming ten times the electric power of a gas station, due to the nature of the business. It is not reasonable to artificially reduce the energy rates paid by the gas station below the average cost to serve it, and then transfer the burden of meeting the revenue shortfall to the energy rate paid by the grocery store in order to send a stronger conservation price signal to the grocer. Such a pricing scheme just creates a new subsidy in which the larger customers on the rate schedule pay for the energy costs of the smaller customers on the rate schedule – without regard to the energy efficiency practices of either.

**Q. What is your recommendation to the Commission on this issue?**

A. Inverted block rates for non-residential customers are entirely inappropriate and should be rejected. The energy charges for small General Service customers should be allowed to vary by season and TOU, but should <u>not</u> vary by monthly consumption levels

**Q. Does this conclude your direct testimony with respect to rate design?**

A. Yes, it does.

# Class Cost of Service Results at Present Rates Including CTC & DSM Revenues
## Using TEP's Filed 4CP Peak and Average Demand Methodology
(Test Period ending June 30, 2006)

| LINE NO. | SUMMARY AT PRESENT RATES WITH DSM & CTC | TOTAL TEP | RESIDENTIAL | GENERAL SERVICE | LARGE LIGHT & POWER | MINING | LIGHTING | PUBLIC AUTHORITY |
|---|---|---|---|---|---|---|---|---|
| 1 | DEVELOPMENT OF RATE BASE | | | | | | | |
| 2 | ELECTRIC PLANT IN SERVICE | $2,115,571,068 | $1,068,181,445 | $759,590,412 | $128,207,739 | $82,733,456 | $24,559,185 | $52,298,831 |
| 3 | RESERVE FOR DEPRECIATION | 1,026,757,960 | 509,322,036 | 366,911,999 | 69,673,770 | 43,178,848 | 12,801,332 | 24,869,975 |
| 4 | DEFERRED TAXES & TAX CREDITS | (165,291,330) | (83,457,906) | (59,347,432) | (10,016,977) | (6,464,034) | (1,918,830) | (4,086,151) |
| 5 | PLANT HELD FOR FUTURE USE | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | REGULATORY ASSESTS | 47,455,224 | 27,185,764 | 16,533,765 | 1,367,569 | 31 | 1,002,665 | 1,365,431 |
| 7 | TOTAL WORKING CAPITAL | 30,273,292 | 14,237,525 | 11,033,609 | 2,324,715 | 1,786,898 | 204,643 | 685,901 |
| 8 | TOTAL CUSTOMER CONTRIBUTIONS | (18,516,132) | (9,339,769) | (6,896,009) | (1,493,091) | 0 | (205,694) | (581,569) |
| 9 | | | | | | | | |
| 10 | TOTAL RATE BASE | $982,734,160 | $507,485,023 | $354,002,346 | $50,716,184 | $34,877,502 | $10,840,637 | $24,812,468 |
| 11 | | | | | | | | |
| 12 | DEVELOPMENT OF RETURN | | | | | | | |
| 13 | SALES OF ELECTRICITY (Excl. DSM & CTC Rev.) | $691,451,429 | $307,535,130 | $274,527,876 | $53,836,878 | $37,790,355 | $4,077,303 | $13,683,888 |
| 14 | DSM & CTC REVENUE | 95,105,561 | 43,045,016 | 36,016,019 | 7,198,893 | 5,933,345 | 408,843 | 2,503,444 |
| 15 | PPFAC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | OTHER OPERATING REVENUE | 21,279,733 | 9,464,534 | 8,448,721 | 1,656,854 | 1,163,015 | 125,481 | 421,128 |
| 17 | TOTAL OPERATING REVENUE | $807,836,724 | $360,044,680 | $318,992,616 | $62,692,626 | $44,886,715 | $4,611,627 | $16,608,460 |
| 18 | | | | | | | | |
| 19 | OPERATING EXPENSES | | | | | | | |
| 20 | OPERATION & MAINTENANCE | $671,184,760 | $308,648,012 | $236,140,504 | $58,446,248 | $49,930,025 | $3,308,685 | $14,711,286 |
| 21 | DEPRECIATION & AMORT EXPENSE | 57,914,052 | 28,793,133 | 20,821,372 | 3,732,441 | 2,557,479 | 615,356 | 1,394,270 |
| 22 | TAXES OTHER THAN INCOME TAX | 29,092,144 | 14,850,047 | 10,420,251 | 1,687,733 | 1,045,047 | 360,280 | 728,785 |
| 23 | | | | | | | | |
| 24 | STATE & FEDERAL INCOME TAX | 5,375,321 | 2,050,213 | 2,491,483 | 267,783 | 310,148 | (22,120) | 277,814 |
| 25 | TOTAL OPERATING EXPENSES | 763,566,277 | 354,341,405 | 269,873,610 | 64,134,205 | 53,842,700 | 4,262,202 | 17,112,156 |
| 26 | | | | | | | | |
| 27 | OPERATING INCOME | 44,270,447 | 5,703,275 | 49,119,006 | (1,441,579) | (8,955,985) | 349,426 | (503,696) |
| 28 | | | | | | | | |
| 29 | RATE OF RETURN (PRESENT WITH DSM & CTC) | 4.50% | 1.12% | 13.88% | -2.84% | -25.68% | 3.22% | -2.03% |
| 30 | | | | | | | | |
| 31 | INDEX RATE OF RETURN (PRESENT WITH DSM & CTC) | 1.00 | 0.25 | 3.08 | (0.63) | (5.70) | 0.72 | (0.45) |

Data Sources: TEP Class Cost of Service Workpapers & TEP Schedule H-2, p. 2 of 3 (Ln 14).

# Class Cost of Service Results at Present Rates Including CTC & DSM Revenues
## Using Calendar Year 2006 4CP/Peak and Average Demand Methodology

SUMMARY AT PRESENT RATES WITH DSM & CTC

| LINE NO. | | TOTAL TEP | RESIDENTIAL | GENERAL SERVICE | LARGE LIGHT & POWER | MINING | LIGHTING | PUBLIC AUTHORITY |
|---|---|---|---|---|---|---|---|---|
| 1 | DEVELOPMENT OF RATE BASE | | | | | | | |
| 2 | ELECTRIC PLANT IN SERVICE | $2,115,571,067 | $1,095,719,785 | $758,006,917 | $109,819,330 | $77,144,694 | $21,612,990 | $53,267,351 |
| 3 | RESERVE FOR DEPRECIATION | 1,026,757,960 | 522,922,828 | 366,581,945 | 59,399,688 | 40,262,048 | 11,491,172 | 26,100,279 |
| 4 | DEFERRED TAXES & TAX CREDITS | (165,291,330) | (85,609,500) | (59,223,712) | (8,580,276) | (6,027,379) | (1,688,641) | (4,161,822) |
| 5 | PLANT HELD FOR FUTURE USE | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | REGULATORY ASSESTS | 47,455,224 | 28,007,704 | 16,560,843 | 1,032,566 | 31 | 880,676 | 973,404 |
| 7 | TOTAL WORKING CAPITAL | 30,273,291 | 14,565,236 | 10,990,610 | 2,036,407 | 1,666,190 | 180,648 | 834,200 |
| 8 | TOTAL CUSTOMER CONTRIBUTIONS | (18,516,132) | (9,790,131) | (7,022,079) | (1,129,490) | 0 | (155,478) | (418,954) |
| 9 | | | | | | | | |
| 10 | TOTAL RATE BASE | $982,734,160 | $519,970,266 | $352,730,634 | $43,778,849 | $32,521,488 | $9,339,023 | $24,393,900 |
| 11 | | | | | | | | |
| 12 | DEVELOPMENT OF RETURN | | | | | | | |
| 13 | SALES OF ELECTRICITY (Excl. DSM & CTC Rev.) | $691,451,429 | $307,535,130 | $274,527,876 | $53,836,878 | $37,790,355 | $4,077,303 | $13,683,888 |
| 14 | DSM & CTC REVENUE | 95,105,561 | 43,045,016 | 36,016,019 | 7,198,893 | 5,933,345 | 408,843 | 2,503,444 |
| 15 | PPFAC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | OTHER OPERATING REVENUE | 21,279,733 | 9,464,534 | 8,448,721 | 1,656,854 | 1,163,015 | 125,481 | 421,128 |
| 17 | TOTAL OPERATING REVENUE | $807,836,724 | $360,044,680 | $318,992,616 | $62,692,626 | $44,886,715 | $4,611,627 | $16,608,460 |
| 18 | | | | | | | | |
| 19 | OPERATING EXPENSES | | | | | | | |
| 20 | OPERATION & MAINTENANCE | $671,184,760 | $312,377,883 | $235,512,521 | $54,749,931 | $48,244,692 | $3,103,270 | $17,196,463 |
| 21 | DEPRECIATION & AMORT EXPENSE | 57,914,053 | 29,508,837 | 20,767,093 | 3,220,523 | 2,384,718 | 544,308 | 1,488,574 |
| 22 | TAXES OTHER THAN INCOME TAX | 29,092,145 | 15,238,935 | 10,401,601 | 1,438,735 | 974,453 | 316,975 | 721,446 |
| 23 | | | | | | | | |
| 24 | STATE & FEDERAL INCOME TAX | 5,375,321 | 1,718,452 | 2,541,953 | 579,612 | 447,917 | (1,006) | 88,394 |
| 25 | TOTAL OPERATING EXPENSES | 763,566,279 | 358,844,107 | 269,223,168 | 59,988,801 | 52,051,780 | 3,963,547 | 19,494,877 |
| 26 | | | | | | | | |
| 27 | OPERATING INCOME | 44,270,444 | 1,200,573 | 49,769,448 | 2,703,825 | (7,165,065) | 648,080 | (2,886,417) |
| 28 | | | | | | | | |
| 29 | RATE OF RETURN (PRESENT WITH DSM & CTC) | 4.50% | 0.23% | 14.11% | 6.18% | -22.03% | 6.94% | -11.83% |
| 30 | | | | | | | | |
| 31 | INDEX RATE OF RETURN (PRESENT WITH DSM & CTC) | 1.00 | 0.05 | 3.13 | 1.37 | (4.89) | 1.54 | (2.63) |

Data Sources: TEP Response to DOD Data Request 3.2 & TEP Schedule H-2, p. 2 of 3 (Ln 14).

# Class Cost of Service Results at Present Rates Including CTC & DSM Revenues
## Using Calendar Year 2006 Average & Excess Demand Methodology

| LINE NO. | SUMMARY AT PRESENT RATES WITH DSM & CTC | TOTAL TEP | RESIDENTIAL | GENERAL SERVICE | LARGE LIGHT & POWER | MINING | LIGHTING | PUBLIC AUTHORITY |
|---|---|---|---|---|---|---|---|---|
| 1 | DEVELOPMENT OF RATE BASE | | | | | | | |
| 2 | ELECTRIC PLANT IN SERVICE | $2,115,571,068 | $1,135,567,813 | $765,979,765 | $94,661,661 | $51,973,643 | $26,993,737 | $40,394,448 |
| 3 | RESERVE FOR DEPRECIATION | 1,026,757,960 | 543,719,692 | 370,743,010 | 51,488,833 | 27,125,164 | 14,299,408 | 19,381,854 |
| 4 | DEFERRED TAXES & TAX CREDITS | (165,291,330) | (88,722,860) | (59,846,637) | (7,395,994) | (4,060,744) | (2,109,043) | (3,156,052) |
| 5 | PLANT HELD FOR FUTURE USE | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | REGULATORY ASSESTS | 47,455,224 | 28,007,704 | 16,560,843 | 1,032,566 | 31 | 880,676 | 973,404 |
| 7 | TOTAL WORKING CAPITAL | 30,273,292 | 15,425,889 | 11,162,810 | 1,709,026 | 1,122,536 | 296,863 | 556,167 |
| 8 | TOTAL CUSTOMER CONTRIBUTIONS | (18,516,132) | (9,790,131) | (7,022,079) | (1,129,490) | 0 | (155,478) | (418,954) |
| 9 | | | | | | | | |
| 10 | TOTAL RATE BASE | $982,734,160 | $536,768,723 | $356,091,692 | $37,388,937 | $21,910,302 | $11,607,347 | $18,967,159 |
| 11 | | | | | | | | |
| 12 | DEVELOPMENT OF RETURN | | | | | | | |
| 13 | SALES OF ELECTRICITY (Excl. DSM & CTC Rev.) | $691,451,429 | $307,535,130 | $274,527,876 | $53,836,878 | $37,790,355 | $4,077,303 | $13,683,888 |
| 14 | DSM & CTC REVENUE | 95,105,561 | 43,045,016 | 36,016,019 | 7,198,893 | 5,933,345 | 408,843 | 2,503,444 |
| 15 | PPFAC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | OTHER OPERATING REVENUE | 21,279,733 | 9,464,534 | 8,448,721 | 1,656,854 | 1,163,015 | 125,481 | 421,128 |
| 17 | TOTAL OPERATING REVENUE | $807,836,724 | $360,044,680 | $318,992,616 | $62,692,626 | $44,886,715 | $4,611,627 | $16,608,460 |
| 18 | | | | | | | | |
| 19 | OPERATING EXPENSES | | | | | | | |
| 20 | OPERATION & MAINTENANCE | $671,184,760 | $324,380,007 | $237,913,194 | $50,186,368 | $40,661,680 | $4,725,594 | $13,317,917 |
| 21 | DEPRECIATION & AMORT EXPENSE | 57,914,052 | 30,740,629 | 21,013,551 | 2,751,965 | 1,606,624 | 710,639 | 1,090,643 |
| 22 | TAXES OTHER THAN INCOME TAX | 29,092,144 | 15,742,275 | 10,502,310 | 1,247,271 | 656,505 | 384,941 | 558,842 |
| 23 | | | | | | | | |
| 24 | STATE & FEDERAL INCOME TAX | 5,375,321 | 736,157 | 2,345,413 | 953,264 | 1,068,410 | (133,647) | 405,725 |
| 25 | TOTAL OPERATING EXPENSES | 763,566,277 | 371,599,068 | 271,774,468 | 55,138,868 | 43,993,219 | 5,687,527 | 15,373,127 |
| 26 | | | | | | | | |
| 27 | OPERATING INCOME | 44,270,447 | (11,554,388) | 47,218,147 | 7,553,758 | 893,496 | (1,075,900) | 1,235,333 |
| 28 | | | | | | | | |
| 29 | RATE OF RETURN (PRESENT WITH DSM & CTC) | 4.50% | -2.15% | 13.26% | 20.20% | 4.08% | -9.27% | 6.51% |
| 30 | | | | | | | | |
| 31 | INDEX RATE OF RETURN (PRESENT WITH DSM & CTC) | 1.00 | (0.48) | 2.94 | 4.48 | 0.91 | (2.06) | 1.45 |

Data Sources: TEP Response to DOD Data Request 6.1 & TEP Schedule H-2, p. 2 of 3 (Ln 14).

# Class Cost of Service Results at Present Rates Including CTC & DSM Revenues
## Using Calendar Year 2006 4CP Demand Methodology

| LINE NO. | SUMMARY AT PRESENT RATES WITH DSM & CTC | TOTAL TEP | RESIDENTIAL | GENERAL SERVICE | LARGE LIGHT & POWER | MINING | LIGHTING | PUBLIC AUTHORITY |
|---|---|---|---|---|---|---|---|---|
| 1 | DEVELOPMENT OF RATE BASE | | | | | | | |
| 2 | ELECTRIC PLANT IN SERVICE | $2,115,571,067 | $1,129,881,806 | $768,065,463 | $89,363,532 | $50,218,999 | $20,021,572 | $58,019,695 |
| 3 | RESERVE FOR DEPRECIATION | 1,026,757,961 | 540,752,139 | 371,831,545 | 48,723,716 | 26,209,408 | 10,660,604 | 28,580,549 |
| 4 | DEFERRED TAXES & TAX CREDITS | (165,291,330) | (88,278,607) | (60,009,595) | (6,982,047) | (3,923,652) | (1,564,302) | (4,533,127) |
| 5 | PLANT HELD FOR FUTURE USE | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | REGULATORY ASSESTS | 47,455,224 | 28,007,704 | 16,560,843 | 1,032,566 | 31 | 880,676 | 973,404 |
| 7 | TOTAL WORKING CAPITAL | 30,273,292 | 15,303,080 | 11,207,858 | 1,594,596 | 1,084,639 | 146,276 | 936,843 |
| 8 | TOTAL CUSTOMER CONTRIBUTIONS | (18,516,132) | (9,790,131) | (7,022,079) | (1,129,490) | 0 | (155,478) | (418,954) |
| 9 | | | | | | | | |
| 10 | TOTAL RATE BASE | $982,734,160 | $534,371,713 | $356,970,945 | $35,155,441 | $21,170,609 | $8,668,140 | $26,397,312 |
| 11 | | | | | | | | |
| 12 | DEVELOPMENT OF RETURN | | | | | | | |
| 13 | SALES OF ELECTRICITY (Excl. DSM & CTC Rev.) | $691,451,429 | $307,535,130 | $274,527,876 | $53,836,878 | $37,790,355 | $4,077,303 | $13,683,888 |
| 14 | DSM & CTC REVENUE | 95,105,561 | 43,045,016 | 36,016,019 | 7,198,893 | 5,933,345 | 408,843 | 2,503,444 |
| 15 | PPFAC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | OTHER OPERATING REVENUE | 21,279,733 | 9,464,534 | 8,448,721 | 1,656,854 | 1,163,015 | 125,481 | 421,128 |
| 17 | TOTAL OPERATING REVENUE | $807,836,724 | $360,044,680 | $318,992,616 | $62,692,626 | $44,886,715 | $4,611,627 | $16,608,460 |
| 18 | | | | | | | | |
| 19 | OPERATING EXPENSES | | | | | | | |
| 20 | OPERATION & MAINTENANCE | $671,184,759 | $322,674,425 | $238,548,893 | $48,582,467 | $40,127,736 | $2,623,575 | $18,627,663 |
| 21 | DEPRECIATION & AMORT EXPENSE | 57,914,052 | 30,564,862 | 21,078,025 | 2,588,188 | 1,552,384 | 495,114 | 1,635,479 |
| 22 | TAXES OTHER THAN INCOME TAX | 29,092,145 | 15,670,452 | 10,528,655 | 1,180,348 | 634,342 | 296,873 | 781,475 |
| 23 | | | | | | | | |
| 24 | STATE & FEDERAL INCOME TAX | 5,375,321 | 876,322 | 2,293,999 | 1,083,869 | 1,111,664 | 38,224 | (28,756) |
| 25 | TOTAL OPERATING EXPENSES | 763,566,277 | 369,786,061 | 272,449,572 | 53,434,872 | 43,426,126 | 3,453,786 | 21,015,861 |
| 26 | | | | | | | | |
| 27 | OPERATING INCOME | 44,270,446 | (9,741,381) | 46,543,044 | 9,257,754 | 1,460,589 | 1,157,841 | (4,407,401) |
| 28 | | | | | | | | |
| 29 | RATE OF RETURN (PRESENT WITH DSM & CTC) | 4.50% | -1.82% | 13.04% | 26.33% | 6.90% | 13.36% | -16.70% |
| 30 | | | | | | | | |
| 31 | INDEX RATE OF RETURN (PRESENT WITH DSM & CTC) | 1.00 | (0.40) | 2.89 | 5.85 | 1.53 | 2.97 | (3.71) |

Data Sources: TEP Response to DOD Data Request 3.3 (Update) & TEP Schedule H-2, p. 2 of 3 (Ln 14).

# AECC Recommended Transmission Cost Allocation and Rate Design
## Using 4CP Class Allocation Factor

### 4CP ALLOCATION FACTORS FOR TRANSMISSION

| Line No. | ALLOCATION FACTOR NAME | TOTAL | RESIDENTIAL | GENERAL SERVICE Without Demand | GENERAL SERVICE With Demand | LARGE LIGHT & POWER | MINING | LIGHTING | PUBLIC AUTHORITY |
|---|---|---|---|---|---|---|---|---|---|
| 1 | DTEHV (4CP) | 100.00% | 48.371% | 27.137% | 10.374% | 6.090% | 4.533% | 0.121% | 3.374% |
| 2 | DPRODAN (4CP exc. R-02 & Comm.-31) | 100.00% | 48.316% | 27.220% | 10.362% | 6.083% | 4.528% | 0.121% | 3.370% |

Data Source: TEP Response to DOD Data Request 3.3 (Update)

### ALLOCATION OF TRANSMISSION EXPENSES USING 4CP ALLOCATION

| Line No. | DESCRIPTION | TOTAL | ALLOC. FACTOR | RESIDENTIAL | GENERAL SERVICE Without Demand | GENERAL SERVICE With Demand | LARGE LIGHT & POWER | MINING | LIGHTING | PUBLIC AUTHORITY |
|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Transmission | 65,605,059 | DTEHV | 31,733,907 | 17,803,147 | 6,806,080 | 3,995,163 | 2,973,887 | 79,562 | 2,213,314 |
| 4 | System control load dispatch | 891,846 | DPRODAN | 430,903 | 242,762 | 92,417 | 54,249 | 40,381 | 1,080 | 30,054 |
| 5 | Reactive supply and voltage control | 3,502,127 | DPRODAN | 1,692,081 | 953,284 | 362,907 | 213,026 | 158,570 | 4,242 | 118,016 |
| 6 | Regulation and frequency response | 3,393,365 | DPRODAN | 1,639,532 | 923,679 | 351,636 | 206,410 | 153,646 | 4,111 | 114,351 |
| 7 | Spinning reserve service | 9,201,240 | DPRODAN | 4,445,655 | 2,504,592 | 953,475 | 559,689 | 416,617 | 11,146 | 310,067 |
| 8 | Supplemental reserve service | 1,500,912 | DPRODAN | 725,178 | 408,551 | 155,531 | 91,297 | 67,959 | 1,818 | 50,578 |
| 9 | Total | 84,094,549 | | 40,667,256 | 22,836,015 | 8,722,046 | 5,119,833 | 3,811,060 | 101,959 | 2,836,380 |

Data Source: TEP Response to DOD Data Request 3.3 (Update) & TEP Cost of Service Rate Design Workpapers

### CLASS BILLING DETERMINANT DATA

| Line No. | | RESIDENTIAL | GENERAL SERVICE Without Demand | GENERAL SERVICE With Demand | LARGE LIGHT & POWER | MINING | LIGHTING | PUBLIC AUTHORITY |
|---|---|---|---|---|---|---|---|---|
| 10 | Billing Determinant On-Peak Demand (kW) | | | 3,486,095 | 1,686,943 | | | |
| 11 | Billing Determinant Energy (kWh) | 3,864,352,371 | 1,981,670,111 | | | | 7,287,604 | 225,259,044 |

Data Source: TEP Cost of Service Rate Design Workpapers

### DERIVATION OF TRANSMISSION CHARGES

| | | RESIDENTIAL | GENERAL SERVICE Without Demand | GENERAL SERVICE With Demand | LARGE LIGHT & POWER | MINING | LIGHTING | PUBLIC AUTHORITY |
|---|---|---|---|---|---|---|---|---|
| 12 | Transmission Rate ($/kW) | | | $2.50 | $3.03 | | | |
| 13 | Transmission Rate ($/kWh) | $0.010524 | $0.011524 | | | | $0.013991 | $0.012592 |

# Large Light and Power (LLP)
# Distribution Cost of Service
# vs. TEP Proposed Distribution Revenues

## TEP LLP Demand-Related Distribution Cost of Service

| Line No. | | LARGE LIGHT & POWER |
|---|---|---|
| 1 | Total Rate Base | $8,892,658 |
| 2 | Claimed Rate of Return (ROR) | 8.35% |
| 3 | Return Required at Claimed ROR | $742,634 |
| 4 | Total Revenue Required at Claimed ROR | $4,062,961 |
| | (Before application any revenue credits) | |

Data Source: TEP Class Cost of Service Study Workpapers

## TEP Proposed LLP Distribution Delivery Revenue

| Line No. | UNBUNDLED SERVICE LLP-14 (NEW TOU LLP-90N) | Adjusted Booked Billing Determinants | Proposed Rate | Proposed Revenue |
|---|---|---|---|---|
| 5 | Delivery Charge (kW) | | | |
| 6 | On-peak | 1,323,916 | $8.00 | $10,591,328 |
| 7 | Off-peak | 1,300,999 | $2.66 | $3,465,861 |
| 8 | Delivery Charge (kWh) | | | |
| 9 | Summer | | | |
| 10 | on-peak | 63,909,719 | $0.020925 | $1,337,330 |
| 11 | off-peak | 208,213,207 | $0.008425 | $1,754,259 |
| 12 | shoulder-peak | 58,804,508 | $0.011245 | $661,274 |
| 13 | Winter | | | |
| 14 | on-peak | 100,230,648 | $0.016955 | $1,699,441 |
| 15 | off-peak | 182,939,210 | $0.004455 | $815,049 |
| 16 | Total LLP-14 Delivery Charge Revenue | | | $20,324,543 |
| | UNBUNDLED SERVICE LLP-90A (NEW TOU LLP-90N) | | | |
| 17 | Delivery Charge (kW) | | | |
| 18 | On-peak | 82,255 | $8.00 | $658,040 |
| 19 | Off-peak | 83,087 | $2.66 | $221,344 |
| 20 | Delivery Charge (kWh) | | | |
| 21 | Summer | | | |
| 22 | on-peak | 5,084,947 | $0.020925 | $106,404 |
| 23 | off-peak | 21,333,365 | $0.008425 | $179,740 |
| 24 | shoulder-peak | 5,113,873 | $0.011245 | $57,507 |
| 25 | Winter | | | |
| 26 | on-peak | 10,062,643 | $0.016955 | $170,615 |
| 27 | off-peak | 20,933,777 | $0.004455 | $93,266 |
| 28 | Total LLP-90A Delivery Charge Revenue | | | $1,486,916 |
| | UNBUNDLED SERVICE LLP-90F (NEW TOU LLP-90N) | | | |
| 29 | Delivery Charge (kW) | | | |
| 30 | On-peak | 280,772 | $8.00 | $2,246,176 |
| 31 | Off-peak | 283,713 | $2.66 | $755,811 |
| 32 | Delivery Charge (kWh) | | | |
| 33 | Summer | | | |
| 34 | on-peak | 16,784,212 | $0.020925 | $351,215 |
| 35 | off-peak | 64,861,794 | $0.008425 | $546,480 |
| 36 | shoulder-peak | 16,713,742 | $0.011245 | $187,951 |
| 37 | Winter | | | |
| 38 | on-peak | 26,993,753 | $0.016955 | $457,687 |
| 39 | off-peak | 53,360,417 | $0.004455 | $237,737 |
| 40 | Total LLP-90F Delivery Charge Revenue | | | $4,783,057 |
| 41 | Total Large Light & Power Delivery Charge Revenue | | | $26,594,516 |

Data Source: TEP Rate Design Workpapers

| | | |
|---|---|---|
| 42 | Distribution Delivery Charge Revenues Above Distribution Cost of Service | $22,531,555 |

# AECC Recommended Rate Spread: Example
## Assumes ACC-Ordered $63 Million Reduction in TEP's Requested Base Revenue Increase

| Line No. | Pricing Plans | Adjusted Present Net Revenue "Including" DSM&CTC Revenue | TEP Proposed Net Increase | TEP Proposed Percent Increase | Step 1 AECC Recommended Reduction Spread | Step 1 Proposed Percent Change | Remaining Net Increase After Step 1 | Step 2 AECC Recommended Reduction Spread | Final AECC Percent Change | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential Service | $352,160,282 | $34,861,888 | 9.90% | $0 | 9.90% | $34,861,888 | $19,173,802 | 5.44% | 1 |
| 2 | General Service | 301,140,659 | 20,842,985 | 6.92% | (20,000,000) | 0.28% | 842,985 | ($12,572,271) | -4.17% | 2 |
| 3 | Large Light & Power | 67,761,730 | 5,057,456 | 7.46% | (10,000,000) | -7.29% | (4,942,544) | ($7,961,204) | -11.75% | 3 |
| 4 | Mines | 43,723,700 | 0 | 0.00% | 0 | 0.00% | 0 | $0 | 0.00% | 4 |
| 5 | Lighting | 5,528,946 | 130,216 | 2.36% | 0 | 2.36% | 130,216 | ($116,088) | -2.10% | 5 |
| 6 | Other Public Authorities | 16,230,658 | 2,198,807 | 13.55% | 0 | 13.55% | 2,198,807 | $1,475,761 | 9.09% | 6 |
| 7 | Subtotal | 786,545,975 | 63,091,352 | 8.02% | (30,000,000) | 4.21% | 33,091,352 | (0) | 0.00% | 7 |
| 8 | Other Operating Revenue | 21,279,733 | 0 | N/A | 0 | N/A | 0 | 0 | N/A | 8 |
| 9 | Total | $807,825,708 | $63,091,352 | 7.81% | ($30,000,000) | 4.10% | $33,091,352 | ($0) | 0.00% | 9 |

Supporting Schedules
(a) H-2 (P2)

**BEFORE THE ARIZONA CORPORATION COMMISSION**

EXHIBIT
AECC-3
admitted

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA | ) | Docket No. E-01933A-07-0402 |
| IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103 | ) | Docket No. E-01933A-05-0650 |

**Direct Testimony of Kevin C. Higgins**

**on behalf of**

**Phelps Dodge Mining Company and**

**Arizonans for Electric Choice and Competition**

**2008 Settlement Agreement**

**June 11, 2008**

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# DIRECT TESTIMONY OF KEVIN C. HIGGINS

## I. Introduction

**Q. Please state your name and business address.**

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

**Q. By whom are you employed and in what capacity?**

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

**Q. Are you the same Kevin C. Higgins who has previously provided direct testimony in this proceeding on behalf of Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition?**

A. Yes, I am.

**Q. What is the purpose of your direct testimony with respect to the Settlement Agreement submitted to the Commission in this docket?**

A. I am testifying in support of the Settlement Agreement submitted to the Commission in this proceeding. To distinguish this agreement from previous agreements I will refer to it as the "2008 Settlement Agreement."

**Q. Were you personally involved in the negotiations that resulted in the 2008 Settlement Agreement?**

A. Yes, I participated in the negotiations on behalf of Phelps Dodge and AECC (collectively referred to herein as "AECC").

**Q. What is your recommendation to the Commission with respect to the 2008 Settlement Agreement?**

A. I recommend that the 2008 Settlement Agreement be approved by the Commission. In my opinion, the 2008 Settlement Agreement produces just and reasonable rates and is in the public interest.

I recommend that new rates go into effect January 1, 2009. I further recommend that the greater of $32.5 million or 50 percent of the True-Up Revenues be credited to customers in the PPFAC balancing account and that TEP be allowed to retain the remainder of the True-Up Revenues as part of the fair resolution of the issues outstanding in this proceeding.

Finally, I do <u>not</u> support Staff's Request for a Procedural Order ("Staff's Request") dated June 6, 2008, which implies that the rate increase proposed in the 2008 Settlement Agreement would have an impact on the special contracts approved by the Commission in Decision No. 65207 and Decision No. 69873. The 2008 Settlement Agreement does <u>not</u> state that the Signatories support modifications to the power supply agreements approved by Decision No. 65207 and Decision No. 69873. AECC considers Staff's Request to be a unilateral action taken outside the scope of the 2008 Settlement Agreement. For the reasons explained in my testimony, AECC recommends that Staff's Request be denied.

## Overall Agreement

**Q. Please provide a general overview as to why you believe the 2008 Settlement Agreement is in the public interest and should be adopted.**

A. The 2008 Settlement Agreement establishes new base rates for TEP that are 6.0 percent higher than current base rates inclusive of the Fixed CTC (but excluding DSM-related revenues in current rates). These new proposed rates were derived using conventional cost-of-service principles; as such, the agreement resolves the major dispute between TEP and other parties as to the appropriate basis – market or cost – for establishing Standard Offer generation rates for the period beginning January 1, 2009. The resolution of this issue is a significant event, as the "market versus cost" dispute had already been the subject of a fully-litigated docket before the Commission in Docket No. E-01933A-05-0650. Moreover, as the "market versus cost" dispute had not been resolved by the Commission in that prior docket, the dispute had been carried forward into this proceeding, and had the potential for continuing beyond this proceeding to the courts. Resolving this issue through negotiation is a significant achievement.

The 2008 Settlement Agreement also provides for base rate stability over the next four years, as under the terms of the agreement, the new base rates negotiated in the agreement are to remain essentially fixed until January 1, 2013. Taken together with the rate cap in place from 1999 until the end of 2008, the 2008 Settlement Agreement will extend a remarkable period of rate stability for TEP customers spanning over thirteen years.

The 2008 Settlement Agreement also calls for the establishment of a Purchased Power and Fuel Adjustment Clause ("PPFAC") that is similar to the mechanism in place for Arizona Public Service Company. This charge would not be levied on low-income residential customers, nor would it apply to direct access service (as direct access customers would receive their generation service from suppliers other than TEP).

In addition, the 2008 Settlement Agreement resolves in an equitable and reasonable manner numerous rate spread and rate design issues that are typical of any rate proceeding. The 6.0 percent revenue increase is to be effected through a 6.1 percent increase on all rate schedules except low-income residential customers, who shall receive no rate increase at all. This approach produces a particularly favorable result for residential customers relative to cost-of-service.

The rate design for non-residential customers properly aligns energy-related costs with energy charges and demand-related costs with demand charges, minimizing cross-subsidies among non-residential customers on the same rate schedules. Further, the 2008 Settlement Agreement provides for optional time-of-use ("TOU") rates for both residential and non-residential customers, giving customers the opportunity to be more responsive to price signals.

The rate design also provides for fully unbundled rates that can accommodate direct access service, consistent with the requirements of the Commission's Electric Competition Rules. As indicated in Paragraph 12.1 of the agreement, the Signatories have agreed that if the Commission desires to address the issue of exclusivity of certificates of convenience and necessity ("CC&N"),

then a generic docket is the appropriate means to do so. No change to TEP's CC&N is proposed in the 2008 Settlement Agreement.

TEP has also committed to work with Staff and interested stakeholders to develop a new partial requirements rate schedule, a new interruptible rate schedule, and a new demand response rate schedule. These new rate schedules would be filed within 90 days of the effective date of the Commission's approval of the 2008 Settlement Agreement.

The 2008 Settlement Agreement also establishes a Demand-Side Management ("DSM") Adjustor mechanism. The initial DSM Adjustor charge of $.000639 would be levied on all retail rate schedules.

Taken as a whole, the 2008 Settlement Agreement provides wide-ranging resolution to most of the issues being contested in this proceeding. I strongly recommend its adoption by the Commission.

**<u>Revenue Requirement</u>**

**Q. In your direct testimony filed February 29, 2008, you recommended that TEP receive a revenue requirement reduction of at least $3.5 million relative to current rates, inclusive of DSM and Fixed CTC. Please explain why a 6 percent overall increase is justified in light of your original recommendation.**

A. In its Application, TEP requested a revenue increase of $180.7 million over current rates (inclusive of Fixed CTC and DSM) under its Cost-of-Service Methodology scenario. TEP's proposal included a Termination Cost Regulatory Asset Charge, and would have increased overall rates 23 percent over current rates. In my direct testimony filed February 29, 2008, I recommended five adjustments totaling $184.2 million that would have resulted in a $3.5 million decrease relative to current revenues.

The 2008 Settlement Agreement provides for a $47.1 million increase over current revenues, which corresponds to a 6 percent overall rate increase. This increase is justified in light of my original recommendation for the following reasons:

(1) The $47.1 million increase recommended in the 2008 Settlement Agreement is the product of negotiation and compromise, an inherent feature of any settlement agreement. To reach agreement to provide a package that is in the public interest, parties must yield on some of their original positions, even if those positions can be defended on a stand alone basis.

(2) My direct testimony recommended a $24.0 million adjustment to base rates to credit customers for 100 percent of the margins from short-term sales. While my recommended adjustment is <u>not</u> included in the <u>base rates</u> established in the settlement agreement, the settlement agreement <u>does</u> provide that customers are credited for 100 percent of the margins from short-term sales as part of the proposed PPFAC. Thus, my concern regarding the proper treatment of the margins from short-term sales is fully addressed in the agreement – it is just addressed via the PPFAC rather than in base rates. Adjusting for this consideration, the revenue increase of $47.1 million recommended in the 2008 Settlement Agreement is just $26.6 million greater than I recommended in my

direct testimony.[1] At the same time, it is $137.1 million less than TEP had recommended in its Cost-of-Service filing in this docket.

(3) The 2008 Settlement Agreement provides a package of results, of which the proposed revenue increase is one component. As described in the overview above, this package includes favorable resolution of the "market versus cost" dispute; a base rate freeze until January 1, 2013; resolution of rate spread issues; improvements to rate design; increased availability of TOU options for customers; and a commitment to develop new partial requirements, interruptible, and demand response rate schedules. Viewed as a whole, the benefits of the settlement package fully justify the compromise on revenue requirement that I am making in reaching agreement with TEP and the other Signatories.

<u>**Start of the Rate Effective Period and True-Up Revenues**</u>

**Q. Section 15.1 of the 2008 Settlement Agreement states that certain issues pertaining to the Fixed CTC True-Up Revenues remain unresolved, and that the Signatories would present their positions with respect to when TEP's new rates may go into effect and how TEP's Fixed CTC True-Up Revenues should be calculated and treated. What is your recommendation on these two points?**

A. I recommend that new rates go into effect January 1, 2009. I further recommend that the greater of $32.5 million or 50 percent of the True-Up Revenues be credited to customers in the PPFAC balancing account and that TEP

[1] $47.1 million – $(3.5 million) + $24.0 million = $26.6 million.

be allowed to retain the remainder of the True-Up Revenues as part of the fair resolution of the issues outstanding in this proceeding.

**Q. Please explain your recommendation concerning the start of the rate effective period.**

A. I believe that January 1, 2009 is the most appropriate date for new rates to go into effect, as it corresponds to the expiration of the rate cap established in the 1999 Settlement Agreement, which extended until December 31, 2008.

**Q. Please explain your recommendation concerning the treatment of True-Up Revenues.**

A. I am very familiar with the origins of the True-Up Revenues. They derive from a provision in the 1999 Settlement Agreement that requires rates to be reduced by the amount of the Fixed CTC at such time that $450 million in stranded cost is recovered. I was closely involved in negotiating that provision on behalf of AECC.

In Decision No. 69568, the Commission modified this requirement of the 1999 Settlement Agreement, and determined that rates would <u>not</u> be reduced by the amount of the Fixed CTC when $450 million in stranded cost was recovered. Instead, the Decision provided that TEP customers should be protected by providing for a mechanism to refund or credit the revenues, plus interest, that will continue to be collected by the modified treatment of the Fixed CTC, until new rates are approved. These revenues are the True-Up Revenues. In its direct filing, TEP estimated that approximately $66 million of True-Up Revenues will be collected between May 2008 and December 31, 2008.[2]

The 2008 Settlement Agreement resolves the "market versus cost" dispute in favor of the positions taken by Staff, RUCO, and AECC. It has been AECC's position, as expressed in my direct testimony filed previously in this case, that AECC would be willing to accept a resolution in which True-Up Revenues were retained by TEP under the Cost-of-Service Methodology, if, and only if, this concession were accompanied by TEP's withdrawal of all claims that the Company would be harmed by setting rates at cost-of-service. The 2008 Settlement Agreement results in such a withdrawal of claims. Therefore, I believe that in the context of the overall settlement, a result that splits the True-Up Revenues between customers and the Company is reasonable. For this reason, I am recommending that the greater of $32.5 million or 50 percent of the True-Up Revenues be credited to customers and that TEP be allowed to retain the remainder of the True-Up Revenues as part of the fair resolution of the issues outstanding in this proceeding. The crediting of the customer share of the True-Up revenues to the PPFAC balancing account is the same recommendation I made on page 42 of my direct testimony filed on February 29, 2008.

It is useful to bear in mind that when the Fixed CTC was established in 1999, it was not a new cost that was added to TEP's existing rates, but a "carve-out" of then-existing rates which was designated for Fixed CTC recovery. Thus, when the Fixed CTC expires, removing this charge would not remove something

[2] Direct testimony of Kentton C. Grant, p. 11, line 23 - p. 12, line 1.

that was "added on" to rates, but rather removal would strip out a pre-existing portion of rates. In the context of the 1999 Settlement Agreement, in which it was anticipated that many customers would be shopping in competitive markets, it was reasonable to expect that the Fixed CTC charge would be extinguished when it had served its purpose of collecting $450 million in stranded cost. However, in the context of the 2008 Settlement Agreement, in which the Signatories believe that a revenue requirement increase over current rates (inclusive of the Fixed CTC) is just and reasonable going forward, and in which the "market versus cost" dispute is resolved in favor of customers, a sharing of the True-Up Revenues between the Company and customers is an appropriate outcome.

## Response to Staff Request for Procedural Order Dated June 6, 2008

**Q. Do you have any comments with respect to Staff's Request for a Procedural Order dated June 6, 2008?**

A. Yes. Staff's Request states that the Settlement Agreement provides for an approximate six percent rate increase across all rate schedules with the exception of the life line rates. Staff's Request then goes on to state: "Such an increase would have an impact on the power supply agreements approved by Decision No. 65207 and Decision No. 69873."

Without addressing the legal aspects of Staff's Request, I do <u>not</u> support Staff's Request as a matter of ratemaking policy nor do I believe that Staff's Request is called for by the 2008 Settlement Agreement.

The 2008 Settlement Agreement does apportion a share of TEP's revenue increase to special contract customers. This has the effect of reducing the revenue requirement increase for the remaining retail customers. Whether the contracts that TEP has voluntarily entered with its two special contract customers allow for the passing on of such a rate increase is an entirely separate matter. Based on my experience with special contracts generally, it is entirely plausible that TEP's special contracts do not permit TEP to pass through rate increases except as already may be specified in the contract terms. TEP entered those contracts voluntarily, and the Company signed the 2008 Settlement Agreement voluntarily. In short, if the terms of the contracts do not permit TEP to recover the increase negotiated in the 2008 Settlement Agreement, then that fact is a part of the calculation that TEP management had to make in signing the agreement. It is not the business of the Signatories of the 2008 Settlement Agreement to impose new terms on contract customers who fairly negotiated power supply agreements with TEP.

Assigning a share of a rate increase to special contract customers – even when those increases cannot be collected under the terms of the contracts – is not at all unusual in ratemaking. It is done to prevent remaining customers from paying a share of the increase that would otherwise be attributable to the contract customers. The utility's ability to collect any such increase assigned to special contracts then comes down to the terms in those agreements. If the contract terms do not permit the pass through of a general rate increase, then the utility absorbs the revenue deficiency. On the other hand, if the contract specifies rate increases in its own terms, then those negotiated increases are not quashed by a different increase adopted in the general rate case.

The 2008 Settlement Agreement does not state that the Signatories support modifications to the power supply agreements approved by Decision No. 65207 and Decision No. 69873. Indeed, AECC would not have supported such a provision.

AECC was neither consulted on Staff's Request nor given advance notice of it. AECC considers Staff's Request to be a unilateral action taken outside the terms of the 2008 Settlement Agreement. For the reasons described above, I recommend that Staff's Request be denied.

**Q. Does this conclude your direct testimony with respect to the 2008 Settlement Agreement?**

A. Yes, it does.

**ARIZONA CORPORATION COMMISSION**

**TUCSON ELECTRIC POWER COMPANY**

**DOCKET NOS. E-01933A-05-0650 & E-01933A-07-0402**

**<u>Settlement Testimony of Dan L. Neidlinger</u>**

**Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.**

A. My name is Dan L. Neidlinger. My business address is 3020 North 17$^{th}$ Drive, Phoenix, Arizona. I am President of Neidlinger & Associates, Ltd., a consulting firm specializing in utility rate economics.

**Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS CASE ON BEHALF OF THE DEPARTMENT OF DEFENSE ("DOD")?**

A. Yes. I filed direct testimony on cost of service, rate design and DSM issues.

**Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?**

A. The purpose of this testimony is provide support for the Settlement Agreement ("Agreement") filed with the Commission on May 29, 2008. The DOD is a signatory to the Agreement. The Agreement, in my view, provides a reasonable balancing of the interests of both Tucson Electric Power Company ("TEP" or the "Company") and its customers.

**Q. WHY DID THE DOD DECIDE TO SUPPORT THE AGREEMENT?**

A. The across-the-board 6.1% revenue increase provided for in the Agreement is contra to the results of the class cost of service analyses discussed in detail in my direct testimony. However, the Agreement incorporates revised rate designs that are consistent with my testimony that called for increased demand charges and lower energy charges. The rate designs proposed in the Company's filings would have unfairly penalized customers with high load factors. Fort Huachuca ("Fort") and Davis Monthan Air Force Base ("DM") are both served under Large Light & Power Rate Schedule 14 ("LLP-14"). Under the new LLP-14 rate, demand charges are increased by approximately $6.00 per Kilowatt ("KW") from present rate levels and summer and winter kilowatt-hour ("kWh") charges reduced by $0.013 and $0.019, respectively. These changes, together with the new optional time-of-use ("TOU"), Rate Schedule LLP-90N ("LLP-90N"), provide both DOD installations with a strong financial incentive to reduce their power costs by reducing and/or shifting peak demands. Both of these rate schedules are provided in Exhibit 8 attached to the Agreement. The potential benefits of these significant rate design changes outweigh any cost of service deficiencies inherent in the across-the-board revenue spread.

**Q. IS THE OPTIONAL TOU RATE LLP-90N A COST-BASED RATE?**

A. Yes, in my opinion, it is. Mandatory TOU rates are not required under the Agreement. However, the optional LLP-90N rate available to both the Fort and DM is a cost-based rate that provides large economic incentives to shift load to off-peak periods. Both of these DOD facilities will give serious consideration to this option.

**Q. ARE THERE OTHER PROVISIONS IN THE AGREEMENT WHICH BENEFIT THE FORT AND DM AS WELL AS THE OTHER CUSTOMERS OF TEP?**

A. Yes, there are a number of other provisions that are of benefit to all customers. First, rates will be set based on the cost of service methodology – the same approach that has been historically used to set rates for TEP. Upon Commission approval of the Agreement, the Company will withdraw its proposed hybrid and market methodology filings. Second, the $788 regulatory asset requested by the Company under the cost of service methodology has been reduced to $14 million. Third, the Agreement provides for a four-year moratorium on increases in base rates. Base rates shall remain frozen through December 31, 2012. Finally, the Agreement provides for the filing within 90 days of the effective date of the Commission's approval of the Agreement the filing of new Partial Requirements Service ('PRS") tariffs, an Interruptible Tariff and a Demand Response Program Tariff.

**Q. DID YOU FILE SUPPLEMENTAL DIRECT TESTIMONY IN THIS CASE REQUESTING CHANGES TO THE CURRENT PRS TARIFFS?**

A. Yes. My testimony[1] on the PRS issue addressed the economic barriers inherent in the Company's current PRS tariffs to the development of large-scale renewable energy projects. The Agreement states that the "tariffs will be designed so as to not inhibit the installation of large solar or other renewable projects"[2].

**Q. HOW WILL THESE TARIFFS BE DEVELOPED?**

A. The Agreement provides that revised PRS tariffs, new interruptible load and demand response tariffs will be developed in consultation with ACC Staff and other interested stakeholders.

**Q. PARAGRAPH 15.1 ON PAGE 18 OF THE AGREEMENT REQUESTS THAT SIGNATORIES TO THE AGREEMENT STATE THEIR POSITION WITH RESPECT TO THE EFFECTIVE DATE OF NEW RATES AND THE TREATMENT OF FIXED CTC TRUE-UP REVENUES. WHAT IS YOUR OPINION ON THESE ISSUES?**

A. I have no objection to implementing prior to January 1, 2009 the rates appended to this Agreement. With respect to the over-collection of fixed CTC revenues, I recommend that all of

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[1] Supplemental Direct Testimony filed in these Dockets and Docket E-01933A-07-0594
[2] Page 26 of the Agreement

these revenues be credited to the PPFAC bank account for the benefit of the Company's customers.

**Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?**

A. Yes, it does.

EXHIBIT
DOD-2
ADMITTED

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**TUCSON ELECTRIC POWER COMPANY**

**DOCKET NOS. E-01933A-05-0650 & E-01933A-07-0402**

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**Direct Testimony of Dan L. Neidlinger**

**On Behalf of**

**The Department of Defense**

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**Electric Cost of Service and Rate Design**

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**March 14, 2008**

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**ARIZONA CORPORATION COMMISSION**

**TUCSON ELECTRIC POWER COMPANY**

**DOCKET NOS. E-01933A-05-0650 & E-01933A-07-0402**

**Direct Testimony of Dan L. Neidlinger**

**Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.**

A. My name is Dan L. Neidlinger. My business address is 3020 North 17th Drive, Phoenix, Arizona. I am President of Neidlinger & Associates, Ltd., a consulting firm specializing in utility rate economics.

**Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.**

A. A summary of my professional qualifications and experience is included in the attached Statement of Qualifications (Attachment A). In addition to the Arizona Corporation Commission ("ACC" or "Commission"), I have presented expert testimony before regulatory commissions and agencies in Alaska, California, Colorado, Guam, Idaho, New Mexico, Nevada, Texas, Utah, Wyoming and the Province of Alberta, Canada.

**Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A. I am appearing on behalf of the Department of Defense ("DOD"). The major DOD installations in Arizona served by Tucson Electric Power Company ("TEP" or the "Company") are Davis Monthan Air Force Base ("DM") located in Tucson and Fort

Huachuca ("Fort") located in Sierra Vista. Both DOD facilities currently receive service from TEP under Rate Schedule LLP-14.

**Q. DID YOU PRESENT TESTIMONY ON BEHALF OF DOD IN TEP'S 05-0650 PROCEEDING?**

A. Yes. The issues presented by TEP in the 05-0650 Docket are again addressed in this case in more detail. The Company has filed in this Docket, 07-0402, three sets of A thru H filing schedules supporting the traditional cost of service ("COS") ratemaking approach as well as the hybrid ("Hybrid") and market ("Market") methodologies discussed in the 05-0650 proceeding. I ask that my testimony in that case be incorporated by reference into the record in this proceeding.

**Q. HAVE YOU CHANGED ANY OF YOUR OPINIONS WITH RESPECT TO THE ISSUES ADDRESSED IN THE 05-0650 CASE?**

A. No, I have not. However, the scope of my testimony in this case is limited to cost of service and rate design issues.

**Q. WHAT IS THE COMBINED ANNUAL ELECTIC USAGE OF THE FORT AND DM?**

A. These military installations are two of the Company's largest customers. Combined annual electric usage for these DOD facilities is approximately 213,000,000 kilowatt hours ("kWh").

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?**

A. My testimony addresses the following issues:

1. The class cost of service study ("CCOSS") supporting the COS filing;
2. The Company's proposed class revenue allocations;

3. The proposed time of use ("TOU") rate design, LLP-90N, for current LLP-14 and LLP-90 customers; and
4. The Company's demand-side management ("DSM") proposals.

The DOD facilities that sponsor my testimony seek no subsidy from other customers of TEP, nor do they wish to subsidize these customers. Their request is straightforward – implement rates that are based on sound cost of service principles.

**Q. IN GENERAL, IS YOUR TESTIMONY ON CCOSS, CLASS REVENUE ALLOCATIONS AND RATE DESIGN ISSUES ALSO APPLICABLE TO THE HYBRID AND MARKET METHODOLGY FILINGS?**

A. Yes.

## I. TESTIMONY SUMMARY

**Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ON CCOSS, CLASS REVENUE ALLOCATION, RATE DESIGN AND DSM ISSUES.**

A. The balance in TEP's rate structure has deteriorated since the last rate 14 years ago. Interclass revenue subsidies have increased since that time and the Company's rate proposals in this case increase, rather than decrease, these subsidies. For instance, the Company is seeking a 35% rate increase (52% greater than the overall increase of 23%) for the Large Light & Power ("LLP") customer class that is currently providing the highest return on rate base of any class. With respect to rate design, the Company's proposed TOU rate for industrial customers, Rate LLP-90N, is not properly designed and provides little incentive to shift load to off-peak periods. Finally, the Company's proposed DSM program needs to be expanded to provide technical and financial assistance to commercial and industrial customers in addition to residential customers. Accordingly, I recommend the following:

- **CCOSS** – The Commission should reject the Company's four-month coincident peak ("4CP") – Average and Peak ("A&P") demand costing method. This method is technically invalid since it double-counts average demand thereby allocating a disproportionate share of fixed production and transmission costs to high load factor customers. Preferable alternative methods are the 4CP method or the Average and Excess method ("A&E"). The latter method considers both energy and class peak demands but does not incorporate the double-counting flaw inherent in the A&P method

- **CLASS REVENUE ALLOCATION** – The increase to the Residential class should be at least 150% of the overall increase. At requested revenue levels, this increase is 34%. Percentage increases to the General Service ("GS") and LLP classes should be no greater than 50% of the overall increase since these classes are currently providing approximately $60 million in revenue subsidies to other classes. At requested revenue levels, this increase is 11.5%. The Mining class rates should be increased by 19% to achieve unity return on rate base and the largest percentage increase, 45%, is recommended for the Other Public Authority ("OPA") class. Under all demand costing methods, the OPA class shows extremely large losses at current rates.

- **LLP-90N RATE DESIGN** – To better reflect demand /energy and seasonal cost differentials, the on-peak summer period demand charge for the proposed LLP-90N TOU rate should be increased from $8.00 to $14.50 per kilowatt ("KW") and winter energy charges reduced. The summer/winter ratio of total revenues under the proposed alternative rate design is 1.66 in contrast to the 1.20 ratio provided by the Company's rate. The proposed LLP-90N rate does not adequately reflect the 1.76 summer/winter ratio in TEP's monthly peak demands.

- **DSM PROGRAMS** – The bulk of the revenues collected to fund DSM programs will be provided by non-residential customers. Accordingly, the scope of the DSM portfolio should be expanded to include those commercial and industrial customers that may need both technical and financial assistance in implementing DSM projects. This funding should be augmented with Utility Energy Service Contracts that require TEP financing of energy efficiency and renewable energy projects for large commercial and industrial customers. Finally, better costing and pricing practices are required to increase the likelihood of achieving successful outcomes from these programs.

As discussed in detail in the following pages of testimony, adoption of these recommendations will provide more realistic approaches for costing and pricing TEP's electric service thereby reducing interclass subsidies. Moreover, they would provide for the design of TOU rates which provide for a strong financial incentive to shift demand to off-peak periods.

## II. <u>CCOSS AND CLASS REVENUE ALLOCATION</u>

**Q. WHY SHOULD ELECTRIC RATES BE PRIMARILY BASED UPON COST OF SERVICE?**

A. In a regulated environment, cost of service is the single-most important criterion in the development of revenues by customer class and the development of rates that will produce those revenues. If rates are not cost-based, the inevitable results are subsidies among classes of customer and customers within a class. Although other factors, such as continuity, simplicity and stability, are valid considerations in the rate design process, the primary guideline should be cost of service. Rates developed based on cost of service considerations are equitable because each customer pays its fair share of the utility's total costs.

**Q. WHAT ARE THE PROBABLE CONSEQUENCES OF SETTING ELECTRIC RATES PRIMARILY ON NON-COST CONSIDERATIONS?**

A. In addition to the inequities previously discussed, basing rates on non-cost considerations can lead to unnecessary departure of large commercial and industrial customers and, in other instances, uneconomic decision-making with respect to energy use and energy alternatives. Utilities with tilted rate structures and obsolete rate designs find themselves scrambling to keep their current commercial and industrial customers on the system without offering special contract rates that are significantly lower that standard rate schedules.

**Q. HOW WOULD YOU CHARACTERIZE TEP'S CURRENT RATE STRUCTURE?**

A. The Company's current rate structure shows significant imbalance as evidenced by the results of the CCOSS filed in this case and discussed in the Direct Testimony of Mr.

Bentley Erdwurm, Lead Analyst in TEP's Rates and Revenue Requirements Department. Mr. Erdwurm's CCOSS for the test year, calendar year 2006, shows extremely large variances in class returns. For instance, Mr. Erdwurm's study[1] shows a negative return for the Residential class of $24.8 million in contrast to the positive return of $28 million for the General Service class on a smaller rate base – a $52.8 million differential. These two customer classes account for over 84% of TEP's total retail electric sales.

**Q. HOW HAS TEP'S RATE STRUCTURE CHANGED SINCE ITS LAST MAJOR RATE PROCEEDING IN 1993?**

A. The balance in the rate structure has deteriorated significantly since that case 14 years ago[2]. At that time, all classes were providing positive returns and the differential between the Residential and GS classes was only $14 million under the same A&P costing methodology. Moreover, TEP's total retail rate base was $138 million higher in 1992 than the total rate base in this case ($1,121 million versus $983 million).

**Q. WHAT ARE THE REASONS FOR THIS DRAMATIC CHANGE?**

A. The root cause of this rate structure deterioration is the failure by both the Company and the Commission to properly set, in prior rate proceedings, class revenue requirements based on sound cost of service principles. As a result, changes in TEP's customer mix and usage patterns since 1992 have exacerbated the interclass subsidy problems present at that time. Exhibit DLN-1, attached, provides a comparison of changes in class revenues, megawatt-hour ("MWH") sales and load factor statistics from 1992 to the current case, calendar year 2006. Although MWH sales increased by 48% during this period, revenues increased by only 36% due to an 8% decrease[3] in the

[1]Updated A&P CCOSS provided in response to DOD Data Request 3.2
[2]Docket U-1933-93-006 – Test Year Ended 6-30-1992
[3]Primarily due to the rate reductions provided for in the 1999 Settlement Agreement

average rate per kWh. Further, residential sales grew at much greater percentage, 82%, than any other customer class. The Residential class was in 1992, and remains today, the least profitable of the Company's major customer classes.

**Q. CAN YOU EXPLAIN THE EROSION IN TOTAL SYSTEM LOAD FACTOR FROM 58% IN 1992 TO 46% IN 2006?**

A. As indicated in the bottom chart on Exhibit DLN-1, this deterioration in load factor is due primarily to the decline in the load factor of the Residential class (53% to 42%) and its increased percentage contribution (48% versus 37%) to TEP's 4CP demand. At current rate levels, revenues from the Residential class are not sufficient to recover the increased costs that the class is imposing on TEP's system.

**Q. DO THE COMPANY'S RATE PROPOSALS IN THIS CASE ADEQUATELY ADDRESS THIS RATE STRUCTURE PROBLEM?**

A. In my view, they do not. Exhibit DLN-2 shows customer class returns on rate base, return indices and revenue subsidies at present and proposed rates under the Company's A&P demand costing methodology. As discussed later in my testimony, the A&P method is technically flawed and an improper demand costing method. However, even under this method, the large disparities in class returns are clearly demonstrated. At present rates, percentage returns on rate base range from a negative 33.95% for the Mines to a positive 7.94% for the GS class. At proposed rates, the Residential class shows a return on rate base of only 4.43% and a return index of .53 whereas the GS and LLP classes show returns on rate base of 16.04% and 22.35%, respectively, and return indices of 1.92 and 2.68. The Company's rate proposals merely perpetuate the interclass subsidies inherent in the present rates.

**Q. WHAT IS THE MEANING OF A RATE OF RETURN INDEX?**

A. A class's rate of return index is a relative measure of its contribution to the system average rate of return. An index that is below 1.00, or negative, indicates that a class's revenues are not sufficient to recover its cost of service, while an index exceeding 1.00 indicates that a class is over-recovering its cost of service, thereby providing revenue subsidies to other classes. Referring again to Exhibit DLN-2, at the Company's proposed rates, the GS and LLP classes are providing over $55 million of revenue subsidies to other customer classes whereas the revenue subsidy received by the Residential class is increased to $34 million.

**Q. PLEASE EXPLAIN EXHIBIT DLN-3.**

A. Exhibit DLN-3 shows present and proposed revenues by customer class and proposed percentage increases. Also shown are class revenue subsidies expressed as a percentage of revenues. As noted, present revenues exclude DSM and Competitive Transition Charges ("CTC") and proposed revenues exclude TEP's proposed Termination Costs Regulatory Asset Charge ("TCRAC"). The Company's proposed revenue spread of the requested $158,186 million increase is not consistent with results of its own CCOSS and should be rejected.

**Q. WHY IS THE A&P METHOD USED BY THE COMPANY TO ALLOCATE DEMAND-RELATED PRODUCTION COSTS TECHNICALLY FLAWED?**

A. The A&P method double-counts average demand: once in the energy component of the formula and again in the 4CP component of the formula. Accordingly, high load factor customers are allocated a disproportionate share of fixed production and transmission plant and related costs under the A&P method. Considering the predominance of TEP'S summer peak, the 4CP method is the most appropriate method for allocating these costs. This method equitably apportions the annual fixed costs incurred by the Company to meet this peak.

**Q. DID THE COMPANY USE THE 4CP METHOD FOR ITS JURISDICTIONAL COST STUDY?**

A. Yes. The wholesale segment of the Company's business should be viewed as another customer class, irrespective of regulatory jurisdiction. If the 4CP method is appropriate for jurisdictional purposes, as advocated by Mr. Erdwurm, it is also appropriate for ACC retail costing.

**Q. PLEASE EXPLAIN THE ILLUSTRATION PROVIDED ON EXHIBIT DLN-4.**

A. The illustration shown on Exhibit DLN-4 compares the results of a demand allocation using the 4CP method and the A&P method for a hypothetical utility with two customer classes. In the base case, both classes are allocated 50 units of demand under the 4CP method. Under the A&P method, Class A receives an allocation of 45 units and Class B an allocation of 55 units – a demand greater than it actually experienced. In the second example, the only change is an increase in Class B's load factor from 60% to 80%. Under the 4CP method, there is no change in the demand allocation between the two classes. However, under the A&P method, Class B's allocation increases by 5 units of demand to 60. Class B has become more efficient in its use of the utility's production facilities but is penalized whereas Class A, which has not changed its behavior, receives a lower allocation of demand costs. A costing method, such as the A&P method, that discourages the efficient use of a utility's resources should be rejected.

**Q. DID THE COMPANY, AT YOUR REQUEST, PREPARE A CCOSS USING THE 4CP DEMAND ALLOCATION METHOD?**

A. Yes. Summary results of that study are shown on Exhibit DLN-5. The returns on rate base at both present and proposed rates for the Residential and OPA classes are lower than the comparable statistics show on Exhibit DLN-2. The higher load factor classes, LLP and the Mines, show much improved returns under the 4CP method due largely to the elimination of the double-counting penalty inherent in the A&P method.

**Q. UNDER THE COMPANY'S A&P COSTING, THE COMPANY IS REQUESTING RATES THAT PROVIDE FOR A 22% RETURN ON RATE BASE FOR THE LARGE LIGHT & POWER CUSTOMER CLASS. UNDER THE 4CP METHOD, THIS RETURN JUMPS TO 46% -- A RETURN THAT IS OVER FIVE TIMES THE OVERALL REQUESTED RETURN OF 8.35%. IS THERE ANY JUSTIFICATION FOR RATES THAT PROVIDE THESE VERY HIGH RETURNS?**

A. Absolutely not. The Company's rate proposals for the LLP class are excessive under either costing methodology. Excluding the off-peak Lighting class, there are only two classes, GS and LLP, which provide return indices at proposed rates that are greater than 1.00 and the LLP class return index of 5.57 is triple the 1.79 index of the GS class. The LLP class is currently providing at present rates the highest return, 13.97%, of any class and yet is asked be burdened with an additional 35% rate increase – an increase that is 52% greater than the overall requested increase of 23%. By any objective measure of reasonableness and fairness, the Company's proposed revenue increases to the LLP class are unsupportable.

**Q. IN PRIOR TEP DECISIONS, THE COMMISSION HAS EXPRESSED THE CONCERN THAT THE 4CP DEMAND ALLOCATION METHOD DOES NOT ADEQUATELY CONSIDER ANNUAL ENERGY USAGE. IS THERE A TECHNICALLY VALID DEMAND ALLOCATION METHOD THAT CONSIDERS AVERAGE ENERGY USAGE IN DETERMINING CLASS ALLOCATION FACTORS?**

A. Yes. The A&E method is a recognized demand allocation method that considers both average demands, or energy use, and class peak demands. Unlike the A&P method, however, the A&E method does not penalize high load factor customers since there is no double-counting of average demand. The Company, again at my request, prepared a CCOSS with demand allocation factors calculated under the A&E method. The average demand component of the calculation was based on annual energy use for each class. The peak demand component of the calculation used maximum, monthly non-coincident peaks ("NCP")[4]. The results of this analysis are summarized on Exhibit DLN-6. As shown on that exhibit, class returns, at both present and proposed rates are comparable to the 4CP results shown on Exhibit DLN-5. The only significant variant is the off-peak Lighting class.

**Q. IN VIEW OF THE THESE CCOSS RESULTS, HOW SHOULD THE COMPANY'S CLASS REVENUE PROPOSALS BE MODIFIED?**

A. Significant changes to the Company's proposals are necessary to improve the balance in the current rate structure. A revised class revenue allocation is provided on Exhibit DLN-7. First, I recommend that the percentage revenue increase for the Residential class be increased to 34% -- eight percentage points greater than the Company's recommended 26% increase. An increase of this magnitude is needed to begin restoring rate structure integrity. Second, smaller relative increases of 11.5% are recommended for the GS and LLP classes in consideration of the large revenue subsidies these classes are currently providing. The Company's proposed increases for these classes[5], as previously discussed, are not supportable under any costing analysis and merely perpetuate the interclass subsidy problem at greater revenue levels. Third, a 19% increase is recommended for the Mining class to move it to unity return, 8.35%, on allocated rate base. Finally, the largest percentage increase for any class, 45%, is

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[4]One variation of the classical A&E formulation is the measurement of class excess demands based on 4CP rather than maximum NCP demands ("4CP A&E"). In this case, class demand allocation percentages produced under the 4CP A&E method are not materially different than those used to produce the results shown on Exhibit DLN-6.

[5]Per Exhibit DLN-3, Company proposed increases for the GS and LLP classes are 17.3% and 35.3%, respectively

recommended for the OPA class. Under all demand costing methods, the OPA class shows extremely large losses at current rates.

**Q. PLEASE EXPLAIN THE RETURN INDICES SHOWN UNDER THE LAST TWO COLUMNS OF EXHIBIT DLN-7.**

A. Class return indices at my recommended revenue spread are shown for the A&E method and the Company's A&P method. While much improved over the Company's proposals, a relatively large return disparity remains among the Residential, GS and LLP classes. These return differences cannot be eliminated without radical rate changes. For instance, to obtain unity return, a 46% increase would be required for the Residential class and while 95% and 81% increases would be required for the Lighting and OPA classes, respectively. The GS and LLP classes would receive small rate reductions. I do not support variances of this magnitude in rate changes among the classes at this time. One should consider in the rate setting process, as previously stated, continuity, simplicity and stability. However, these ratemaking attributes have often been used in the past as justification for making rate decisions for TEP that largely ignore cost of service. The grim results of these ratemaking policies are clearly demonstrated on Exhibit DLN-1. I fear that the system inefficiencies shown on that exhibit will continue under the Company's class revenue and rate design proposals.

**Q. ARE YOU ENDORSING THE OVERALL REVENUE LEVELS REQUESTED BY TEP?**

No. The DOD has no recommendation with respect to overall revenue requirements. The recommended class revenue allocation (Exhibit DLN-7) is provided to illustrate an equitable assignment of revenue responsibility at the overall revenue level requested by the Company. The increase in total revenues authorized by the Commission should be apportioned among the classes as follows:

| | | |
|---|---|---|
| • | Residential | 66.7% |
| • | GS | 20.0% |
| • | LL&P | 3.9% |
| • | Mining | 4.5% |
| • | Lighting | 1.0% |
| • | OPA | 3.9% |

These percentages are consistent with the class allocations shown on Exhibit DLN-7.

**Q. WHAT INCREASE IN TOTAL REVENUES DO THE ACC STAFF, RUCO AND AECC SUPPORT IN THIS CASE?**

A. Staff is recommending an overall revenue increase of $9,766,000[6] or 1.4%. RUCO recommends a 4.04%[7] increase of $36,254,000. AECC's recommended increase is $91,619,000 or 13.25%. Based on these recommendations and the class apportionment factors discussed above, the revenue spreads would be approximately as follows:

| | | STAFF | RUCO | AECC |
|---|---|---|---|---|
| • | Residential | $6,514,000 | $24,181,000 | $61,110,000 |
| • | GS | 1,953,000 | 7,251,000 | 18,324,000 |
| • | LL&P | 381,000 | 1,414,000 | 3,573,000 |
| • | Mining | 439,000 | 1,631,000 | 4,123,000 |
| • | Lighting | 98,000 | 363,000 | 916,000 |
| • | OPA | 381,000 | 1,414,000 | 3,573,000 |

This revenue allocation is provided for comparative purposes with the revenue increases shown on Exhibit DLN-7 using the Company's proposed revenue requirement. As previously stated, the DOD has no recommendation on overall revenue requirements.

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[6]Staff's alternative return on fair value produces an overall increase of $17.84 million or 2.6%.
[7]This is a 5.24% increase on adjusted test year revenues of $691,451,429; RUCO 4.04% calculation includes sales for resale and other operating revenues in present revenues.

## III. RATE DESIGN

**Q. HAVE YOU REVIEWED THE RATE DESIGN RECOMMENDATIONS OF MR. ERDWURM?**

A. I have generally reviewed most of Mr. Erdwurm's rate design proposals for the various classes. I have specifically analyzed in detail the proposed TOU rate LLP-90N[8] that would replace the current LLP-14 and LLP-90 rates.

**Q. DO EITHER DM OR THE FORT OBJECT TO THE IMPOSITION OF A MANDATORY TOU RATE?**

A. No, they do not. A properly designed TOU rate would provide both DOD facilities with additional incentives to shift on-peak load to off-peak periods. They do object, however, to the TOU rate design proposed by the Company. Rather than encouraging improved efficiency, the proposed LLP-90N rate provides little incentive to either of these DOD customers to shift load.

**Q. PLEASE EXPLAIN.**

A. Typical bill comparisons[9] under TOU rate LLP-90N indicate that high load factor customers will incur a greater percentage increase in bills than less-efficient, low load factor customers. This phenomenon is the result of recovery of an excessive amount, over 50%, of demand-related costs in the energy component of the rate. Although consistent with the Company's proposed A&P costing method, this rate design is contra to the load-shifting objectives of TOU rates[10] and proposed DSM programs[11]. To

[8]Schedule H-3, Page 14 of 16, Cost of Service Filing
[9]Schedule H-4, Page 23 of 28, Cost of Service Filing
[10]Direct Testimony of Bentley Erdwurm, Page 30
[11]Direct Testimony of Denise A. Smith, Page 3

achieve these objectives, the summer period peak-demand component of the rate must be increased significantly to recover a greater percentage of demand-related costs.

**Q. ARE OTHER CHANGES TO RATE LLP-90N NEEDED, IN YOUR VIEW?**

A. Yes. Of equal importance to the demand/energy mix is the seasonal aspect of the rate. The rate does not reflect the very large summer/winter demand differential. Exhibit DLN-8 shows monthly peak demands for calendar year 2006. The ratio of maximum monthly peak (July) to minimum monthly peak (February) is over 2.00. The ratio of summer peak to winter peak is 1.76. These ratios not only provide guidance with respect to CCOSS demand costing but also the degree of seasonality to be incorporated in the rate design. The ratio of summer/winter demand charges in the proposed LLP-90N is only 1.33 and the comparable ratio for total charges, including fuel and purchased power, is 1.20. Both of these ratios are well short of the cost differentials implied by TEP's peaking characteristics.

**Q. ARE THESE LOW SEASONAL RATIOS ALSO PREVALENT IN THE TOU RATES PROPOSED FOR OTHER CUSTOMER CLASSES?**

A. I have not analyzed the proposed TOU rates for other customer classes in detail. However, the ratios appear to be higher than the ratios for the proposed LLP-90N rate. For instance, the second tier (501-3,500 kWh's) of the proposed residential TOU Rate R-70N[12] for the summer on-peak period is only $0.0123 higher than the second tier of this rate for the winter on-peak period but the ratio of summer/winter revenues are much greater than 1.33 since the bulk of residential usage occurs during the summer period. Also, in contrast to the LLP-90N rate design, a strong load shifting incentive is incorporated the R-70N rate. The summer on/off peak differential is almost $0.10 per kWh.

There are other unexplainable differences among the Company's TOU rate design proposals, notably the variances in winter season off-peak fuel and purchased power rates. These rates range from $0.0111 per kWh (less than cost) under the R-70N rate to

[12]Schedule H-3, Page 2 of 16, Cost of Service Filing

$0.0357 per kWh under the LLP-90N rate. The latter rate is higher than the on-peak fuel and purchased power rate of $0.0288.

**Q. HAVE YOU DESIGNED AN ALTERNATIVE TOU RATE WHICH BETTER REFLECTS DIFFERENCES IN SEASONAL COSTS AND PROVIDES IMPROVED INCENTIVES TO SHIFT LOAD TO OFF-PEAK PERIODS?**

A. Yes. The TOU rate shown on Exhibit DLN-9 was developed to illustrate the type of rate design that I recommend be adopted in this case. It is designed to mirror the revenue requirements used to develop LLP-90N – the Company's proposed revenues for the LLP customer class. Accordingly, I am not recommending the level of the rate components but only the demand/energy and seasonal relationships demonstrated by the proposed design. The rate incorporates much higher on-peak demand and energy charges during the summer period to encourage load shifting to off-peak periods. In addition, summer/winter ratios for demand charges and total charges are increased to 1.69 and 1.66, respectively – ratios that are much closer to the seasonal load relationships shown on Exhibit DLN-8. The shoulder rating periods during the summer have been eliminated; the on-peak period during the summer is 12:00 noon to 8:00 P.M. In sum, the alternative TOU rate does a better job of reflecting TEP's costs than the LLP-90N rate.

**Q. WHY AREN'T WEEKENDS OFF-PEAK?**

A. In most electric utilities, the weekday diversity provided by commercial and industrial customers produces relatively large load reductions on the weekends. Accordingly, weekends are normally off-peak periods under TOU rates. TEP's system loads, however, are driven by the residential class which exhibits no significant load reduction during the weekends. In fact, the residential class's monthly peak demand occurred four times on a Saturday or Sunday during 2006[13]. This anomaly is also a

[13]See TEP's response to RUCO Data Request 3.6

major consideration in the establishment of two (morning and evening) on-peak periods during the winter season.

**Q. CAN YOU QUANTIFY THE IMPROVEMENT IN LOAD SHIFTING INCENTIVES PROVIDED BY YOUR ALTERNATIVE RATE DESIGN?**

A. Yes. A comparison (alternative rate design versus LLP-90N) of the monthly and annual benefits from shifting 1 KW of demand at a 70% load factor from on-peak to off-peak periods is provided on Exhibit DLN-10. The annual savings under the alternative rate are $225 or 42% greater than the $158 savings achieved under the Company's proposed LLP-90N rate. The proposed alternative rate design has not only a sounder cost foundation but also provides a much greater financial incentive to shift load to off-peak periods.

**Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE RIDER 5 – THE TRANSMISSION COST ADJUSTMENT CHARGE ("TCA")?**

A. Yes. I have no general objection to flowing-through to retail customers adjustments made by the Federal Energy Regulatory Commission's ("FERC") to TEP's transmission tariffs ("OATT"). I do object, however, to the manner in which TEP proposes to establish and implement Rider 5. First, the OATT is a demand-based tariff, not an energy charge. TEP has converted all of customer class OATT demand charges into energy charges and proposes to make future adjustments on a kWh basis without considering line and transformation losses. This approach is not cost-based and should be rejected by the Commission. Where practicable, the TCA charge for customer classes should be set on a demand or KW basis consistent with charges under the OAAT. Arizona Public Service Company[14] recently received Commission approval of a TCA that provides for demand charges for all customers with demands over 20 KW. Second, adjustments under Rider 5 should be calculated in a manner consistent with FERC's

[14]Decision No. 70179, ACC Docket No. E-01345A-07-0713

formula method which provides for a reconciliation of prior over or under collections. Finally, regardless of the basis setting and adjusting the rate (KW or kWh), line and transformation losses should be included in the rate calculations.

**Q. DON'T MOST ELECTRIC UTILITIES ADJUST FOR KW AND KWH LOSSES IN THEIR COSTING PRACTICES?**

A. Yes, except for TEP. Adjusting for losses by voltage level of service is standard practice in the electric utility industry. Loss factors are typically used in cost of service studies and applied to adjustment clauses such as fuel and purchased power adjustors. Loss factors were not used in TEP's CCOSS and there is no mention of loss adjustment factors by Company witness David Hutchens in his testimony on a proposed purchased power and fuel adjustment clause ("PPFAC'). If losses are not considered, customers taking service at primary and transmission voltages will pay energy charges that exceed cost and customers taking service at secondary voltage levels will pay energy charges that are lower than cost.

## IV. TEP'S PROPOSED DSM PROGRAM

**Q. HAVE YOU REVIEWED THE COMPANY'S DSM PROPOSALS AS DISCUSSED IN THE TESTIMONIES OF MS. DENISE SMITH AND MR. THOMAS HANSEN?**

A. Yes. The Company is recommending that funding for DSM programs be increased from the current $3.1 million to $12.4 million. Details of the Company's expanded DSM portfolio are discussed by Ms. Smith; Mr. Hansen's testimony deals with recommended DSM cost recovery mechanisms through a DSM adjustor that would appear as a line item on customers' bills. The bulk of the proposed expenditures are targeted for DSM programs for residential and small commercial customers. It is unlikely that either the Fort or DM would receive any benefits from the proposed portfolio but would be required to provide over $395,000[15] annually to fund the programs.

**Q. ARE YOU SUGGESTING THAT THE FORT AND DM BE EXPEMPT FROM DSM CHARGES?**

A. No. Both of these DOD installations are currently providing DSM funds to TEP and are agreeable to continue this funding if the programs can actually reduce total system costs. To date, however, it is evident from the facts in this case that the current programs have had little impact on system efficiencies. Larger commercial and industrial customers provide a significant portion of total DSM funding. It follows that TEP be required to broaden the scope of its DSM portfolio to include programs for those larger customers that may need technical and financial assistance in evaluating and implementing DSM applications. In addition to direct funding under the DSM portfolio, there are probably numerous other large-customer DSM projects that could be implemented through Utilities Energy Services Contracts ("UESC'S")

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[15]Second tier rate of $0.001859 per kWh, Exhibit TNH Page 2 of 2.

**Q. WHAT ARE UESC'S?**

A. A UESC is a contract between the utility and customer to install energy efficient equipment, processes and systems on the customer's premises that are deemed to be economically feasible. Utilities throughout the U.S. have entered into these contracts with both government and non-government customers; they are cooperative efforts aimed at saving costs to both the utility and the customer. These projects are typically financed by the utility which earns a defined rate of return on monies invested. Energy savings provide customers the ability to refund to the utility the cost of the project over a specified period of years.[16] DSM technologies funded under this approach include lighting, building insulation, HVAC equipment, motors, pumps, thermal storage and shading structures over chillers and cooling towers. Renewable energy projects including solar, wind and biomass generators would also be candidates for this type of funding.

**Q. DID EITHER OF THE COMPANY'S DSM WITNESSES DISCUSS THE USE OF UESC'S AS A VIABLE APPROACH FOR FINANCING DSM OR RENEWABLE ENERGY PROJECTS?**

A. Ms. Smith did not discuss these contracts. Mr. Hansen briefly discusses on Page 12 of his testimony the need for a higher rate of return on DSM projects financed by the Company that are "outside of the DSM program" and covered under a one-time agreement akin, I assume, to a UESC. UESC's would provide an important financing vehicle to fill the void in the Company's proposed DSM program with respect to large commercial and industrial customers. They would also provide the Company with an opportunity to earn additional income on monies invested under UESC's. Accordingly, I urge the Commission to include UESC's as another component of TEP's DSM portfolio.

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[16]The terms of these contracts range from 5 to 20 years.

**Q. WHAT ABOUT MR. HANSEN'S PROPOSAL TO RECOVER A RATE OF RETURN PREMIUM ON "HIGH EFFICIENCY CAPITAL EXPENDITURES"?**

A. In my view, the Company does not need any additional financial incentive to construct energy-efficient plant since these investments accrue to the benefit of the Company's profits. The purpose of the DSM program is to change the behavior of the customer, not the Company. Similarly, the Company shouldn't need additional financial incentives to assist customers with projects, such as thermal storage, that reduce peak load. A thermal storage project financed under a UESC provides the Company with a guarantee that it will receive its authorized rate of return on the project as well as recover a portion of lost revenues attributable to reduced demands and energy usage.

**Q. ARE LOAD-SHIFTING PROJECTS FOR LARGE CUSTOMERS, LIKE THERMAL STORAGE, ECONOMICALLY ATTRACTIVE UNDER THE COMPANY'S PROPOSED TOU RATES?**

A. As previously discussed, the meager benefits of load-shifting under the Company's proposed TOU rates would probably not support economic feasibility for most of these projects. The proposed alternative rate form, however, would significantly improve the economic attractiveness of load-shifting projects like thermal storage. Due to faulty costing and pricing practices, the Company has failed to properly synchronize its rate design proposals with the load reduction objectives of its DSM programs.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Historical Comparisons - 1992 vs 2006**
**$(000)**

| Customer Class | 1992 Revenues | 1992 MWH Sales | 2006 Revenues | 2006 MWH Sales | Percentage Increase (Decrease) Revenues | Percentage Increase (Decrease) MWH Sales |
|---|---|---|---|---|---|---|
| Residential | $190,021 | 2,117,799 | $307,535 | 3,864,352 | 61.84% | 82.47% |
| General Service | 203,842 | 2,184,851 | 274,528 | 3,314,379 | 34.68% | 51.70% |
| Large Light & Power (1) | 71,007 | 1,149,742 | 53,837 | 948,945 | -24.18% | -17.46% |
| Mines | 31,604 | 670,865 | 37,790 | 924,898 | 19.57% | 37.87% |
| Lighting | 3,368 | 31,269 | 4,077 | 41,016 | 21.05% | 31.17% |
| Other Public Authority | 9,818 | 138,674 | 13,684 | 225,259 | 39.38% | 62.44% |
| Total TEP | $509,660 | 6,293,200 | $691,451 | 9,318,849 | 35.67% | 48.08% |
| Rate Per kWh | $0.08099 | | $0.07420 | | -8.38% | |

| Customer Class | 1992 Average 4CP Demand (2) | 1992 Load Factor (3) | 2006 Average 4CP Demand (2) | 2006 Load Factor (3) | Percentage Increase (Decrease) Average 4CP Demand | Percentage Increase (Decrease) Load Factor |
|---|---|---|---|---|---|---|
| Residential | 460 | 52.56% | 1,061 | 41.58% | 130.65% | -20.89% |
| General Service | 528 | 47.24% | 825 | 45.86% | 56.25% | -2.92% |
| Large Light & Power (1) | 157 | 83.60% | 134 | 80.84% | -14.65% | -3.30% |
| Mines | 76 | 100.77% | 99 | 106.65% | 30.26% | 5.84% |
| Lighting (4) | 1 | NM | 3 | NM | NM | |
| Other Public Authority | 25 | 63.32% | 74 | 34.75% | 196.00% | -45.12% |
| Total TEP | 1,247 | 57.61% | 2,196 | 46.44% | 76.10% | -19.39% |

NOTES:
(1) Changes in Large Light & Power Class revenues and MWH sales due primarily to reclassification of certain customers to other rates.
(2) Average of class 4 coincident summer peak demand (4CP) - Megawatts.
(3) Annual load factor calculated based on average 4CP demand.
(4) Off-peak load; NM=Not Meaningful

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Class Returns on Rate Base and Revenue Subsidies at Present and Proposed Rates**
**4CP Average and Peak ( A&P) Demand Methodology (1)**
**$(000)**

| | Return on Rate Base | | Return Index | | Revenue Subsidy (2) | |
|---|---|---|---|---|---|---|
| **Customer Class** | **Present Rates** | **Proposed Rates** | **Present Rates** | **Proposed Rates** | **Present Rates** | **Proposed Rates** |
| Residential | -4.77% | 4.43% | -3.56 | 0.53 | ($29,611) | ($33,822) |
| General Service | 7.94% | 16.04% | 5.93 | 1.92 | 54,384 | 45,063 |
| Large Light & Power | -3.76% | 22.35% | -2.80 | 2.68 | (1,756) | 10,179 |
| Mines | -33.95% | -22.07% | -24.66 | -2.64 | (17,129) | (16,430) |
| Lighting | 4.30% | 14.49% | 3.20 | 1.74 | 874 | 953 |
| Other Public Authority | -18.03% | -6.32% | -13.45 | -0.76 | (6,762) | (5,943) |
| Total TEP | -1.34% | 8.35% | 1.00 | 1.00 | $0 | $0 |

NOTES:
(1) TEP's proposed demand allocation method as discussed in the Direct Testimony of Mr. Bentley Erdwurm
(2) Positive number Indicates the amount of subsidy a class is providing; bracketed or negative number indicates the amount of subsidy a class is receiving.

EXHIBIT DLN - 3

**TUCSON ELECTRIC POWER COMPANY**
**Docket nos. E-01933A-05-0650 & 07-402**
**Electric Cost of Service and Rate Design**

**Class Revenue Subsidies as a Percentage of Present and Proposed Revenues**
**A&P Demand Methodology**
**$(000)**

| | | | | | Revenue Subsidies as A Percent of: (1) | |
|---|---|---|---|---|---|---|
| Customer Class | Present Revenues (2) | Proposed Revenues (3) | Proposed Increase | Percent Increase | Present Revenues | Proposed Revenues |
| Residential | $307,535 | $387,022 | $79,487 | 25.85% | -9.63% | -8.74% |
| General Service | 274,528 | 321,984 | 47,456 | 17.29% | 19.81% | 14.00% |
| Large Light & Power | 53,837 | 72,819 | 18,982 | 35.26% | -3.26% | 13.98% |
| Mines | 37,790 | 43,724 | 5,934 | 15.70% | -45.33% | -37.58% |
| Lighting | 4,077 | 5,659 | 1,582 | 38.80% | 21.44% | 16.84% |
| Other Public Authority | 13,684 | 18,429 | 4,745 | 34.68% | -49.42% | -32.25% |
| Total TEP | $691,451 | $849,637 | $158,186 | 22.88% | 0.00% | 0.00% |

NOTES:
(1) Dollar amount of class subsidies are shown on Exhibit DLN - 2.
(2) Excluding DSM & CTC Revenues
(3) Excluding Proposed Termination Costs Regulatory Asset Charge ("TCRAC")

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Demand Illustration - 4CP vs A&P**

## BASE CASE

| Customer Class | Average Demand | Demand Allocation 4CP Method (1) | A&P Method (2) | Over (Under) Allocation |
|---|---|---|---|---|
| A | 20 | 50 | 45 | (5) |
| B | 30 | 50 | 55 | 5 |
| Total | 50 | 100 | 100 | 0 |

## CUSTOMER CLASS B INCREASES LOAD FACTOR

| Customer Class | Average Demand | Demand Allocation 4CP Method (1) | A&P Method (2) | Over (Under) Allocation |
|---|---|---|---|---|
| A | 20 | 50 | 40 | (10) |
| B | 40 | 50 | 60 | 10 |
| Total | 60 | 100 | 100 | 0 |

NOTES:
(1) 4CP allocation formula: Class contribution to 4CP demand
(2) A&P allocation formula: (SLF%)(AD%) + (1-SLF%)(4CP%) where SLF=System load factor, AD=Class average demand and 4CP=Class contribution to 4CP demand.

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Class Returns on Rate Base and Revenue Subsidies at Present and Proposed Rates**
**4CP Demand Methodology (1)**
**$(000)**

| | Return on Rate Base | | Return Index | | Revenue Subsidy (2) | |
|---|---|---|---|---|---|---|
| **Customer Class** | **Present Rates** | **Proposed Rates** | **Present Rates** | **Proposed Rates** | **Present Rates** | **Proposed Rates** |
| Residential | -6.69% | 2.27% | -4.99 | 0.27 | ($47,464) | ($53,993) |
| General Service | 6.94% | 14.95% | 5.18 | 1.79 | 49,120 | 39,116 |
| Large Light & Power | 13.97% | 46.48% | 10.42 | 5.57 | 8,937 | 22,261 |
| Mines | -10.03% | 6.85% | -7.48 | 0.82 | (3,055) | (529) |
| Lighting | 10.51% | 21.50% | 7.84 | 2.57 | 1,706 | 1,892 |
| Other Public Authority | -22.42% | -11.60% | -16.73 | -1.39 | (9,244) | (8,747) |
| Total TEP | -1.34% | 8.35% | 1.00 | 1.00 | $0 | $0 |

NOTES:
(1) Per CCOSS provided in response to DOD Data Request 3.3
(2) Positive number Indicates the amount of subsidy a class is providing; bracketed or negative number indicates the amount of subsidy a class is receiving.

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Class Returns on Rate Base and Revenue Subsidies at Present and Proposed Rates**
**A&E Demand Methodology (1)**
**$(000)**

| | Return on Rate Base | | Return Index | | Revenue Subsidy (2) | |
|---|---|---|---|---|---|---|
| **Customer Class** | **Present Rates** | **Proposed Rates** | **Present Rates** | **Proposed Rates** | **Present Rates** | **Proposed Rates** |
| Residential | -7.30% | 1.57% | -5.45 | 0.19 | ($53,386) | ($60,691) |
| General Service | 8.69% | 16.87% | 6.48 | 2.02 | 58,252 | 49,437 |
| Large Light & Power | 12.00% | 43.81% | 8.95 | 5.25 | 7,962 | 21,161 |
| Mines | -11.54% | 4.95% | -8.61 | 0.59 | (3,670) | (1,223) |
| Lighting | -11.70% | -3.53% | -8.73 | -0.42 | (2,008) | (2,303) |
| Other Public Authority | -18.77% | -7.20% | -0.14 | -0.86 | (7,150) | (6,381) |
| Total TEP | -1.34% | 8.35% | 1.00 | 1.00 | $0 | $0 |

NOTES:
(1) Per CCOSS provided in response to DOD Data Request 5.3
(2) Positive number Indicates the amount of subsidy a class is providing; bracketed or negative number indicates the amount of subsidy a class is receiving.

**TUCSON ELECTRIC POWER COMPANY**
**Docket nos. E-01933A-05-0650 & 07-402**
**Electric Cost of Service and Rate Design**

**Recommended Class Revenue Allocation**
**$(000)**

| | | DOD Recommendations (1) | | | Return Index at Proposed Rates | |
|---|---|---|---|---|---|---|
| **Customer Class** | **Present Revenues (2)** | **Proposed Revenues (3)** | **Proposed Increase** | **Percent Increase** | **A&E Method** | **A&P Method** |
| Residential | $307,535 | $413,069 | $105,534 | 34.32% | 0.54 | 0.89 |
| General Service | 274,528 | 306,104 | 31,576 | 11.50% | 1.69 | 1.60 |
| Large Light & Power | 53,837 | 60,029 | 6,192 | 11.50% | 2.68 | 0.57 |
| Mines | 37,790 | 44,946 | 7,156 | 18.94% | 1.00 | -2.37 |
| Lighting | 4,077 | 5,659 | 1,582 | 38.80% | -0.42 | 1.74 |
| Other Public Authority | 13,684 | 19,830 | 6,146 | 44.91% | -0.45 | -0.34 |
| Total TEP | $691,451 | $849,637 | $158,186 | 22.88% | 1.00 | 1.00 |

NOTES:
(1) Recommended revenue spread based on total revenue levels requested by the Company
(2) Excluding DSM & CTC Revenues
(3) Excluding Proposed Termination Costs Regulatory Asset Charge ("TCRAC")

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**2006 Monthly System Peak Demands**

| MONTH | Peak Demand In Megawatts (1) | Percent of Annual System Peak |
|---|---|---|
| January | 1,243 | 53% |
| February | 1,145 | 48% |
| March | 1,160 | 49% |
| April | 1,383 | 58% |
| May | 1,875 | 79% |
| June | 2,220 | 94% |
| July | 2,365 | 100% |
| August | 2,194 | 93% |
| September | 2,049 | 87% |
| October | 1,819 | 77% |
| November | 1,296 | 55% |
| December | 1,341 | 57% |
| Average 2006 | 1,674 | 71% |
| Ratio of Maximum to Minimum Monthly Peak | | 2.07 |
| Ratio of Summer Peak to Winter Peak | | 1.76 |
| Ratio of Maximum to Average Monthly Peak | | 1.41 |

NOTE:
(1) Response to DOD Data Request 1.6

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Illustrative Alternative Seasonal TOU Rate Design - LLP-90N Rate Schedule**

| | SEASON | |
|---|---|---|
| **RATE COMPONENT** | **SUMMER (1)** | **WINTER (2)** |
| Customer Charges - Per Month | $500 | $500 |
| Demand Charges - Per KW: | | |
| On-Peak (3) | $14.50 | $8.00 |
| Off-Peak (4) | $2.30 | $2.30 |
| Energy Charges - Per kWh: | | |
| On-Peak (3) | $0.0685 | $0.0450 |
| Off-Peak (4) | $0.0425 | $0.0325 |

NOTES:
(1) May through October
(2) November through April
(3) Summer: Daily 12:00 Noon - 8:00 P.M., Winter: 6:00 A.M - 10:00 A.M. and 5:00 P.M - 9:00 P.M.
(4) Summer: Daily 8:00 P.M - 12:00 Noon, Winter: 10:00 A.M - 5:00 P.M. and 9:00 P.M - 10:00 A.M.

**TUCSON ELECTRIC POWER COMPANY**
**Docket Nos. E-01933A-05-0650 & 07-0402**
**Electric Cost of Service and Rate Design**

**Load Shifting Benefits - Alternative Rate Design vs LLP-90N**

| DESCRIPTION | Benefits of Shifting 1KW from Peak to Off-Peak (1) Alternative Rate | LLP-90N |
|---|---|---|
| SUMMER: | | |
| Monthly On-Peak Charges | $49.50 | $44.98 |
| Monthly Off-Peak Charges | 24.02 | 26.87 |
| Monthly Benefit | $25.48 | $18.11 |
| Benefit Per kWh | $0.04986 | $0.03544 |
| WINTER: | | |
| Monthly On-Peak Charges | $31.00 | $37.41 |
| Monthly Off-Peak Charges | 18.91 | 29.20 |
| Monthly Benefit | $12.09 | $8.21 |
| Benefit Per kWh | $0.02366 | $0.01607 |
| ANNUAL BENEFIT: | | |
| Summer | $152.88 | $108.66 |
| Winter | 72.54 | 49.26 |
| Total Year | $225.42 | $157.92 |
| Per kWh | $0.03676 | $0.02575 |

NOTES:
(1) Shifting of 1KW demand and 511 kWh (70% Load Factor) from peak period to off peak period

EXHIBIT
IBEW-1
ADMITTED

RECEIVED
FEB 29 2008
ARIZONA CORP. COMMISSION
CORPORATIONS DIVISION

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BEFORE THE ARIZONA

CORPORATION COMMISSION

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION FOR TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHANGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA | Docket No. E-01933A-07-0420 |
| IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62013 | Docket No. E-01933A-05-0650 |

NOTICE OF FILING DIRECT
TESTIMONY OF FRANK GRIJALVA

Pursuant to the Administrative Law Judge's Procedural Order (p. 3) dated October 5, 2007, Local Union 1116, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 1116"), by and through undersigned counsel, hereby provides notice of its filing of the attached Direct Testimony of Frank Grijalva in this docket.

RESPECTFULLY SUBMITTED this 29th day of February, 2008.

LUBIN & ENOCH, P.C.

Nicholas J. Enoch, Esq.
Attorney for Intervenor IBEW Local 1116

ORIGINAL and thirteen (13) copies
of IBEW Local 1116's Notice filed
this 29th day of February, 2008, with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing transmitted
electronically/mailed this
same date to:

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Hearing Division
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F:\Law Offices\client directory\IBEW L. 1116\014\Pleadings\2008-02-29Notof Filing wpd

**Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A1. Frank Grijalva. My business address is 750 South Tucson Boulevard, Tucson, Arizona 85716-5689.

**Q2. PLEASE DESCRIBE YOUR RECENT EMPLOYMENT.**

A2. I am the Business Manager/Financial Secretary for Intervenor Local Union 1116, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 1116"). The position of Business Manager/Financial Secretary is an elected union position and, due to the retirement of my predecessor, I was appointed by our Executive Board to my present position in October 2007. Because all IBEW local unions also have a person holding the position of "President," it is common for persons outside of our organization to believe that the "President" is the principal officer of the Local. That is not the case. Article 17, §§ 4 and 8 of the Constitution of the International Brotherhood of Electrical Workers, AFL-CIO, clearly states that the Business Manager/Financial Secretary is the "principal officer" of any IBEW local union.

Prior to my becoming Business Manager/Financial Secretary for IBEW Local 1116, I was employed by the Tucson Electric Power Company ("TEP") for twenty-two (22) years in a variety of bargaining unit positions, the last of which was as a Designer for Transmission and Distribution Construction. While employed at TEP, I was a very active member of IBEW Local 1116, including previously serving as the Local's President and in other positions on the Executive Board.

**Q3. WHAT IS IBEW LOCAL 1116?**

A3. IBEW Local 1116 is the labor organization which serves as the exclusive representative for, *inter alia*, approximately six hundred seventy-five (675) non-managerial workers at TEP. IBEW Local 1116 and TEP have entered into a long series of collective bargaining agreements dating back to November 16, 1937 concerning rates of pay, wages, hours of employment, and other terms and conditions of employment.

**Q4. DO YOU BELIEVE TEP IS A RESPONSIBLE CORPORATE CITIZEN?**

A4. Absolutely. While by no means perfect, the relationship between IBEW Local 1116 and TEP is one which is mature and stable. It is clear that this stability has benefitted TEP, its employees, and customers. In my opinion, the importance of the strong and stable relationship between a public service corporation and its employees cannot be overstated. I believe that my opinion in this regard is widely shared.

During a hearing before this Commission several years ago *In the matter of UniSource's Reorganization*, Docket No. E-04230A-03-0933, James S. Pignatelli, the President and Chief Executive Officer of both TEP and its parent company, UniSource Energy Corporation ("UniSource"), recognized that the harmonious relationship between the IBEW Local 1116 and UniSource inevitably leads to a stable work environment which, in turn, helps the preservation of health and safety for the employees of UniSource. Mr. Pignatelli defined the public interest as, *inter alia*, providing a safe and secure working environment for the employees.

Mr. Pignatelli also agreed with the notion that acrimonious relations between a public service corporation and the certified representative of its employees will almost certainly hinder the company's ability to provide safe, reasonable, and adequate service. He also acknowledged that an acrimonious relationship may also impair the ability of the public service corporation to attract capital at fair and reasonable terms. I share Mr. Pignatelli's views in this regard.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5. As you know, Article XV, §3 of the Arizona Constitution expressly states that the interests of public service employees are on par with those of patrons. It reads as follows:

> The corporation commission shall have full power to, and shall ... make reasonable rules, regulations, and orders, by which such [public service] corporations shall be governed in the transaction of business within the State, and ... make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the

preservation of the health, of the *employees* and patrons of such corporations[.]

On behalf of its own members, as well as several hundred thousand patrons of TEP, IBEW Local 1116 believes this proceeding provides it with a unique and timely opportunity to express to this Commission our qualified support of TEP's Application and our reasons for doing so.

**Q6. DO YOU BELIEVE THAT TEP IS ENTITLED TO AN INCREASE ITS RETAIL RATES EFFECTIVE NO LATER THAN JANUARY 1, 2009?**

A6. Yes.

**Q7. WHICH OF THE THREE PROPOSED METHODOLOGIES DOES IBEW LOCAL 1116 SUPPORT?**

A7. IBEW Local 1116 supports the so-called "Cost-of-Service Methodology". At the very best, the so-called "Market Methodology" would place the employees and patrons of TEP and, indeed, TEP itself in a highly precarious position along the lines of what transpired in California just a few years ago. This is one of the central points made by the IBEW's International President in a Statement he issued on August 19, 2003, a copy of which is attached hereto as Exhibit A.

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Q8. IN ITS COST-OF-SERVICE METHODOLOGY, TEP SEEKS RECOVERY OF APPROXIMATELY $835 MILLION IN COSTS AND LOSSES ASSOCIATED WITH THE FAILED TRANSITION TO RETAIL COMPETITION. DOES IBEW LOCAL 1116 SUPPORT THIS REQUEST?

A8. Generally speaking, yes. At the outset I must admit that IBEW Local 1116 has not undertaken an extensive examination of the specific size of the request and, as such, cannot speak to the reasonableness of the $835 million figure. With that qualification, IBEW Local 1116 firmly believes that TEP management prudently and in good faith spent many millions of dollars in response to this Commission's earlier - and in our opinion ill-conceived - decision to transition TEP toward market-based rates. IBEW Local 1116 believes that TEP is entitled to substantial rate relief from this Commission with due consideration of the tremendous amount of money wasted, albeit unwittingly, by TEP transitioning its business plan from a cost-of-service basis back to a cost-of-service basis.

Q9. IN ITS COST-OF-SERVICE METHODOLOGY, TEP SEEKS TO IMPLEMENT A PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE TO ENSURE TIMELY RECOVERY OF TEP'S POWER SUPPLY COSTS. DOES IBEW LOCAL 1116 SUPPORT THIS REQUEST?

A9. Yes.

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Q10. DURING HIS TESTIMONY ON MARCH 6, 2007,[1] MR. PIGNATELLI DISCUSSED THE INCREASE HEALTH CARE EXPENSE ASSOCIATED WITH TEP'S EMPLOYEE BENEFITS PACKAGE. IN BOTH TEP'S APPLICATION[2] AND RECENTLY FILED DIRECT TESTIMONY OF MICHAEL J. DeCONCINI, TEP'S SENIOR VICE PRESIDENT AND CHIEF OPERATING OFFICER FOR TRANSMISSION AND DISTRIBUTION,[3] TEP ALLUDED TO THE SAME CONCERNS. DO YOU HAVE ANY COMMENTS OR OBSERVATIONS THAT YOU WOULD LIKE TO SHARE WITH THE COMMISSION REGARDING THIS TOPIC?

A10. Yes. While IBEW Local 1116 does not dispute the fact that the costs associated with employee benefit plans and, in particular, health care insurance have grown significantly in recent years, I also believe that the point should be made that IBEW Local 1116 has made concessions and has agreed to health plans that have cost its represented employees more in out-of-pocket expenses. An increase in rates should be such that it would eliminate whatever pressure is on TEP to increasingly shift healthcare costs to its represented employees.

In the most recent year of 2007, in an attempt to reduce its health plan cost, TEP unilaterally made changes with some healthcare related benefits for its retirees in a manner it believes is consistent with the National Labor Relations Act

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[1] *See* Hearing Transcript Volume I, page 81, lines 12-21.

[2] *See* page 4, line 15.

[3] *See* page 31, lines 4-5.

of 1935, 29 U.S.C. § 151, *et seq.*, the Employee Retirement Income Security Act of 1974, 29 U.S.C. § 1001, *et seq.* and our collective bargaining agreement. Likewise, it appears to me that TEP management believes that it is within their province to make similar unilateral changes to the benefits package of their unionized employees. It is my hope that with an increase in rates this will eliminate TEP's need to unilaterally make changes to reduce healthcare benefits for or shift costs to its employees.

**Q11. DO YOU HAVE ANY FINAL COMMENTS?**

A11. Yes. IBEW Local 1116 believes that two of the symptoms identified by President Hill in his attached statement - *to wit*, a low employee count and deferred equipment maintenance - are already present at TEP and, in the absence of prompt and substantial relief from this Commission, they will continue to grow. As such, IBEW Local 1116 respectfully submits that TEP and its employees need prompt rate relief from this Commission to address these mounting concerns.

**Q12. DOES THIS CONCLUDE YOUR TESTIMONY?**

A12. Yes.

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# Exhibit A

# NEWS RELEASE

International Brotherhood of Electrical Workers®
AFL-CIO-CLC
1125 Fifteenth St. N.W.
Washington DC 20005
www.ibew.org

Edwin D. Hill, International President
Jeremiah J. O'Connor, International Secretary-Treasurer

**August 19, 2003**

**Contact**: Malinda Brent 202-728-6134

## Statement of International Brotherhood of Electrical Workers

## President Edwin D. Hill on Largest Power Failure in U.S. History

Last week's power failure for 50 million Americans may well have stemmed from an overworked transmission system, a severe reduction of the work force and deferred equipment maintenance—all developments that followed deregulation.

Deregulation promised benefits from competitive markets, but it also brought uncertainty, which froze investment in new construction. In the 10 years since utility deregulation was first introduced, power companies have built or updated very few new transmission lines. Today demand continues to climb, but transmission investment in 2000 was less than half of what it was in 1975. In general, training programs for workers have been reduced or suspended indefinitely. The work force has been reduced by one third in the past 10 years, with an obvious impact on maintenance.

In fact, deferred maintenance has become the hallmark of deregulation. In order to maximize profitability, maintenance schedules in many utilities have been extended from six months to two or three years, greatly adding to system risk. Because electricity is often generated hundreds of miles from its user, the system is increasingly interconnected. When one or two elements of such a highly integrated system break down, the result is cascading blackouts like the one that occurred last week.

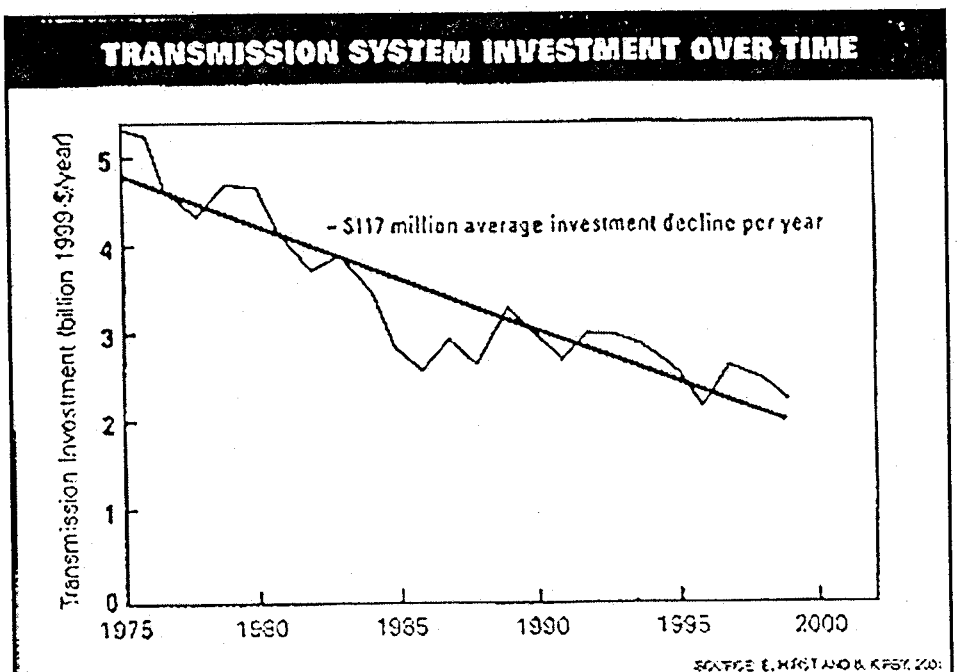
Deregulation provides incentives to a utility company to sell electricity across state and national boundaries, but it is transmitted on a grid initially designed to deliver only to its local customers. What happened last week is bound to happen again, given the growing demand for electricity.

In recent years, deregulation has caused blackouts in the West and manipulation of power markets by the likes of Enron and others. If we continue down this road, the fallout will become national. Power outages will become a way of life.

It is a cause of grave concern that utility deregulation has turned the once reliable, self-sustaining utility business into a marketplace where profit-taking trumps reliability. Consumers, businesses and industries are more at risk since electricity was redefined as a commodity rather than as a necessary service.

The IBEW urges policy makers to conduct an independent, engineering-based investigation into the blackout. Our modern electricity-dependent society should not be left to the mercies of today's deregulated utilities.

*The IBEW represents 220,000 utility workers in the United States and Canada.*




*As this graph shows, investment in new transmission facilities has been declining steadily for 25 years.*

###

FILE COPY

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EXHIBIT
IBEW-2
ADMITTED

Attorneys for Intervenor IBEW Local 1116

BEFORE THE ARIZONA

CORPORATION COMMISSION

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| IN THE MATTER OF THE APPLICATION FOR TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHANGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA | Docket No. E-01933A-07-0402 |
| IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62013 | Docket No. E-01933A-05-0650 |

NOTICE OF FILING DIRECT TESTIMONY OF FRANK GRIJALVA IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

Pursuant to the Administrative Law Judge's Procedural Order (p. 2) dated May 12, 2008, Local Union 1116, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 1116"), by and through undersigned counsel, hereby provides notice of its filing of the attached Direct Testimony of Frank Grijalva in this docket.

RESPECTFULLY SUBMITTED this 19th day of June, 2008.

LUBIN & ENOCH, P.C.

Nicholas J. Enoch, Esq.
Attorney for Intervenor IBEW Local 1116

ORIGINAL and thirteen (13) copies of IBEW Local 1116's Notice filed this 19th day of June, 2008, with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing transmitted electronically/mailed this same date to:

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F:\Law Offices client directory\IBEW L 1116\014\Pleadings\2009-06 19 Nte of Filing Dir Testimony of F Grijalva wpd

Q1. PLEASE STATE YOUR NAME.

A1. Frank Grijalva.

Q2. ARE YOU THE SAME FRANK GRIJALVA WHOSE DIRECT TESTIMONY WAS FILED IN THIS MATTER ON FEBRUARY 29, 2008?

A2. Yes.

Q3. DOES INTERVENOR LOCAL UNION 1116, INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, CLC ("IBEW Local 1116") SUPPORT THE ADOPTION OF THE MAY 29, 2008 SETTLEMENT AGREEMENT.

A3. Yes. On behalf of the approximately six-hundred and seventy-five (675) non-managerial workers at the Tucson Electric Power Company ("TEP") who are represented by IBEW Local 1116, I would like to express the Union's unqualified support for the proposed Settlement Agreement.

Q4. ARE THERE SPECIFIC PORTIONS OF THE SETTLEMENT AGREEMENT THAT IBEW LOCAL 1116 IS PARTICULARLY INTERESTED IN?

A4. Yes. While IBEW Local 1116 supports the adoption of proposed Settlement Agreement in its entirety, IBEW Local 1116 took a particularly active role in negotiating and/or otherwise considering the following specific paragraphs of the proposed Settlement Agreement: ¶¶ 1.14(ii) and 2.2.

Q5. PLEASE EXPLAIN WHY IBEW LOCAL 1116 IS PARTICULARLY INTERESTED IN ¶ 1.14(ii).

A5. Paragraph 1.14(ii) simply acknowledges the fact that Article XV, § 3 of the Arizona Constitution places the interests of public service employees on par with those of patrons. The interests of both constituencies, in turn, are of more importance than those of the corporation's shareholders.

**Q6. ARE YOU AWARE OF ANY LEGAL AUTHORITY SUPPORTING THIS PROPOSITION?**

A6. Certainly. In its 1984 decision in *Cogent Pub. Serv. v. Arizona Corp. Comm'n*, 142 Ariz. 52, 56-57, 688 P.2d 698, 702-03, Division One expressly, and my opinion correctly, held that "the jurisprudence of our State made it plain long ago that the interests of public-service corporation stockholders must not be permitted to overshadow those of the public served." In support of this quite unremarkable proposition, our Court of Appeals relied upon a series of U.S. and Arizona Supreme Court decisions dating back to 1896.[1] Beyond that, I would also point out that Article XV, § 3 of the Arizona Constitution does not mention shareholders.

**Q7. PLEASE EXPLAIN WHY IBEW LOCAL 1116 IS PARTICULARLY INTERESTED IN ¶ 2.2.**

A7. For the reasons set forth in my previous testimony, the 750,000-member International Brotherhood of Electrical Workers strongly opposes any regulatory move toward, and thus supports any retreat from, a so-called "competitive retail market". In my opinion, this Commission made a serious mistake back in 1996 when it created, and later revised, the Retail Electric Competition Rules. Division

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[1] *See Salt River Valley Canal Co. v. Nelssen*, 10 Ariz. 9, 13, 85 P. 117, 119 (1906) [*citing Covington & Lexington Turnpike Road Co. v. Sanford*, 164 U.S. 578, 596, 17 S.Ct. 198, 205, 41 L.Ed.560, 566 (1896)].

One's 2004 decision in *Phelps Dodge Corp. v. Ariz. Elec. Power Coop., Inc.*, 207 Ariz. 95, 83 P.3d 573, rectified the serious legal problems associated the Retail Electric Competition Rules. In much the same way, I firmly believe that the adoption of the instant Settlement Agreement is a wise and correct step for this Commission to transition back to the time-tested notion that rates ought to be premised upon a thoroughly prepared cost-of-service analysis and not on some seriously flawed notion that a competitive retail market does, or ever will, exist in Arizona. While Adam Smith's "invisible hand," in which market transactions take place, and supply, demand, price and allocation of goods and services are determined, as buyers and sellers haggle over commodities in a competitive market, may be a worthwhile topic for discussion in a first-year economics class in college, it simply does not provide a viable way to provide electric service to millions of Arizonans. For better or worse, some industries, such as public utilities, are so structured that only a small number of firms or only one firm may enter a market. Entry costs are high and viable alternatives are not available. The instant Settlement Agreement recognizes the fact that the underlying ideology of government regulation is to correct inequities in markets in response to the reality that markets do not always run smoothly.

**Q8. ARE THERE ANY PORTIONS OF THE PROPOSED SETTLEMENT AGREEMENT THAT IBEW LOCAL 1116 IS LESS PLEASED WITH.**

A8. Sure. For example, IBEW Local 1116 would have preferred that the important matters addressed in ¶ 12.1 had been tackled in the instant proceeding instead of some yet-to-be filed generic docket. Similarly, IBEW Local 1116 would have preferred that TEP receive even more - potentially far more - rate relief than what is set forth in herein. Notwithstanding these reservations, however, IBEW Local 1116 recognizes that the consummation of a comprehensive Settlement Agreement amongst nine (9) different parties with often times disparate and competing interests is no so small feat. It is for that reason that IBEW Local 1116 fully and strongly supports the Commission's adoption of the proposed Settlement Agreement *in toto*.

**Q9. DO YOU HAVE ANY OTHER COMMENTS YOU WOULD LIKE TO SHARE WITH THE COMMISSION REGARDING THE INSTANT SETTLEMENT?**

A9. Yes. I want to make it abundantly clear to the Commission and TEP that, by agreeing to this Settlement Agreement, IBEW Local 1116 has not, and does not, agree to any modification, express or implied, to the terms and conditions of its collective bargaining agreement with TEP. That is not to say that I believe this will ever become a problem vis-á-vis IBEW Local 1116's relationship with TEP; in fact, I do not believe that is the case. Nevertheless, I just want to make certain that there is no confusion in this regard moving forward.

**Q10. DOES THIS CONCLUDE YOUR TESTIMONY?**

A10. Yes.

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ADMITTED

Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

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|---|---|
| In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103 | ) Docket No. E-01933A-05-0650 |
| In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona | ) Docket No. E-01933A-07-0402 |

**DIRECT TESTIMONY**

**AND EXHIBITS**

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

Arizona Corporation Commission
DOCKETED
MAR 14 2008
DOCKETED BY nr

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2008

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

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|---|---|
| **In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103** | **) Docket No. E-01933A-05-0650<br>)** |
| **In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona** | **)<br>)<br>) Docket No. E-01933A-07-0402<br>)<br>)** |

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**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

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**DIRECT TESTIMONY OF STEPHEN J. BARON**

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

**Q. What is your occupation and by who are you employed?**

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

**Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.**

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

**Q. Please state your educational background.**

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

**Q. Please describe your professional experience.**

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Wisconsin; before the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

**Q. Have you previously presented testimony before the Arizona Corporation Commission?**

A. Yes. I presented testimony in a Tucson Electric Power Company proceeding in 1981 on behalf of the Commission (Docket No. U-1933I). I also presented testimony in two Arizona Public Service Company rate cases on behalf of Kroger Co. (Docket Nos. E-01345-03-0437 and E-01345A-05-0816).

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Kroger Co. Kroger has approximately 22 stores and other facilities in the TEP service territory. These stores consume in excess of 48 million kWhs per year on the TEP system.

**Q. What is the purpose of your testimony?**

A. I will be presenting testimony on a number of cost of service and rate design issues that affect Kroger's service on TEP's General Service rate schedules, primarily rate GS-85.[1] As I will discuss, I do not support the Company's proposed Average and Peaks class cost of service methodology in this case. A 4CP methodology is more appropriate for retail cost allocation and is consistent with the Company's proposed jurisdictional allocation methodology.

With regard to rate design, I will discuss the Company's proposed revisions to its time-of-day rates, specifically focusing on rate GS-85N. TEP is proposing the elimination of a substantial portion of the current rate GS-85 kW demand charges and rolling these amounts into its proposed time-of-day energy charges. As I will discuss, this causes a substantial portion of the GS-85N transmission charge (which is demand related) to be recovered through off-peak energy charges. This is not reasonable and should be corrected. I will also discuss other rate design problems that I have identified with the proposed GS-85N rate related to the recovery of demand cost through the energy charges of the rate.

Q. **Would you please summarize your recommendations?**

A. Yes.

- **TEP's "average and peaks"class cost of service methodology is not reasonable and should be rejected. The Company uses a 4 CP methodology for jurisdictional allocation of generation and transmission-related costs. For the same reasons cited by TEP witness Erdwurm to support the use of the 4 CP method for jurisdictional cost allocation, the 4 CP method is also appropriate for retail class cost of service allocation.**

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[1] Kroger is not presenting testimony on the Company's requested revenue increase in this case. This should not be construed as an endorsement of the Company's requested increase.

- **Even if the Commission continues to use the average and peaks methodology to allocate generation-related costs to retail rate classes, the Commission should require TEP to revise its class cost of service study to incorporate a 4 CP allocator for transmission costs, since these costs are incurred by TEP on the basis of 4 CP demands.**

- **The Company's proposed rates for Rate schedule GS-85N substantially exceed cost of service (calculated using TEP's average and peaks class cost of service study), under both the "Cost of Service" and "Hybrid" regulatory schemes. The proposed increase to GS-85N should be reduced to address this unreasonable subsidy payment that is produced by the Company's recommendations in this case.**

- **TEP's proposed rate design for rate schedule GS-85N is unreasonable because it understates the kW demand charge of the rate and overstates the time-of-day energy charges. The Company's proposed rate design improperly recovers demand related distribution, transmission and generation costs through energy charges. Rate GS-85N should be revised to recover a greater portion of demand related costs through kW demand charges.**

- **In the event that the Commission approves the recovery of the Company's proposed TCRA regulatory asset, it is inappropriate to recover the cost on a uniform kWh basis. It is reasonable to assume that the revenue deficiency used to compute the regulatory asset was produced by rate schedules in proportion to their individual rate base amounts on which rate of return and income deficiencies are determined, not on kWh energy use. If the recovery of the regulatory asset is approved by the Commission, the TCRA should be allocated to rate schedules on the basis of rate base, not kWh energy use.**

## II. REVENUE ALLOCATION AND COST OF SERVICE

**Q. Have you reviewed the Company's 12 month ending December 2006 test year cost of service study filed in this proceeding?**

A. Yes. The Company is utilizing a 4 coincident peak and average demand ("Average & Peaks") cost of service study in this proceeding to allocate production and transmission demand costs to retail rate classes. For jurisdictional cost allocation, the Company allocates generation and transmission-related demand costs using a 4 CP methodology (not the average and peaks method). According to TEP witness D. Bentley Erdwurm,

> **Coincident peak demand determines the maximum capacity of the system. It is the demand of each jurisdiction at system peak that determines each jurisdiction's use of that capacity".** (direct testimony at page 5, line 7).

I support the use of a 4 CP methodology to allocate generation and transmission-related demand costs to jurisdictions and among retail rate schedules. For the same reasons cited by Mr. Erdwurm to support the use of the 4 CP method for jurisdictional cost allocation, the 4 CP method is also appropriate for retail class cost of service allocation.

**Q, How does TEP reconcile the use of a 4 CP allocation method for jurisdictional cost allocation and an "average and peaks" methodology for retail class cost allocation?**

A. I don't believe that the Company has adequately reconciled these two very different cost causation theories. Beginning on page 21 if his testimony, Mr. Erdwurm states that the average and peaks method is the methodology previously adopted by the Commission and also argues that the average and peaks method recognizes that base load units produce fuel savings, relative to less efficient gas fired peaking units. This argument, which is commonly referred to as the "capital substitution" theory, relies on the economic tradeoffs in resource planning between base load, intermediate and peaking capacity. However, there is no foundation presented by TEP in this case for the specific use of an allocation factor based on a weighting of average demand and peak demand. The weight, which in the TEP analysis, is based on the system load factor, is not supported by any cost analysis that attempts to measure the economic tradeoffs between the costs of a base load unit, versus a peaking or intermediate unit. The so-called "weight" used by the Company is arbitrary.

Q. **What support has the Company provided in its testimony for the allocation of transmission costs using the average and peaks allocation factor?**

A. There is no such support, nor is there any legitimate basis to use an average and peaks methodology to allocate transmission costs. Transmission costs are incurred by TEP to serve retail customers based on 4 CP kW demands, not "average and peaks." Even if the Commission continues to use the average and peaks methodology to allocate generation-related costs to retail rate classes, the Commission should require TEP to revise its class cost of service study to incorporate a 4 CP allocator for transmission costs.

Q. **Do you believe that the Company's average and peaks cost of service study provides a reasonable basis to evaluate the relationship between the rates being charged each rate class and the underlying cost of providing service to these customers?**

A. No. For the same reasons cited by the Company in support of a 4 CP method for jurisdiction cost allocation, I believe that the 4 CP method should be used for retail class cost of service purposes. As I discussed above, at a minimum, transmission costs should be allocated using the 4 CP allocator, since there is obviously no economic justification for use of an average demand allocation factor for transmission expenses incurred by TEP pursuant to its OATT. Though I am not presenting an alternative 4 CP class cost of service study in this case, I believe that the Commission should adopt such a methodology for purposes of assessing the reasonableness of TEP's retail rates, in relation to the underlying cost of providing service to the customers on each rate class.

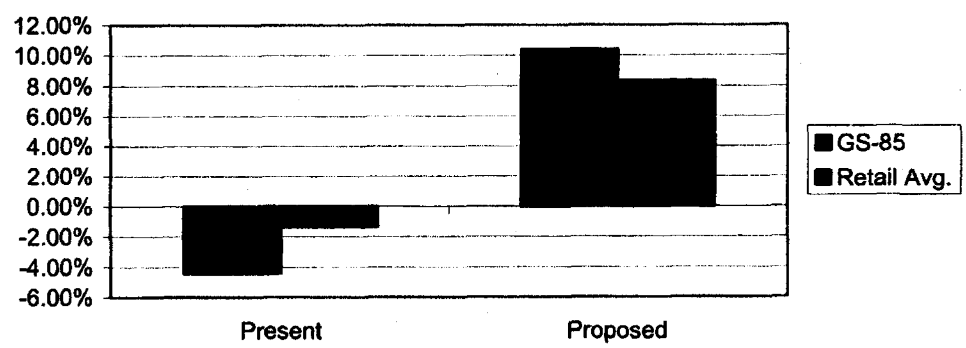
**Q. How do the Company's current rates compare to the underlying cost of service?**

A. Notwithstanding my previous discussion of the problems with the Company's average and peaks class cost of service study, the results of the Company's filed study show that a number of rate classes are earning rates of return below the system average rate of return.

**Q. Has the Company attempted to move rate schedule rates of return toward equality in its proposed rates for each schedule?**

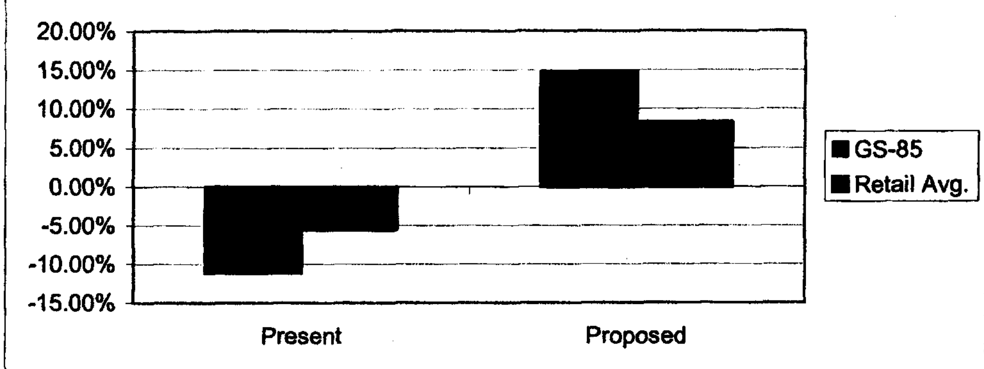
A. Yes. Again, notwithstanding my objection to the Company's class cost of service study methodology, TEP has attempted to move class rates of return. However, in the case of rate schedule GS-85, the Company's proposed rates substantially exceed cost of service, under both the "Cost of Service" and "Hybrid" regulatory schemes. Figures 1 and 2 below show the rates of return for current rate GS-85 at present and proposed rates, compared to the system average rate of return. As can be seen from the charts, the Company has moved rate GS-85 from a position below cost of service to above cost of service in this case. Since GS-85 customers have a relatively high load factor, the use of a 4 CP cost of service methodology would show even greater disparities between rates and cost, at the proposed GS-85N rate for these customers.[2]

**Figure 1**
**Rate of Return at Present and Proposed Rates**
**GS-85 versus Retail Average ("Cost of Service Methodology")**




[2] Under the Company's proposal, current GS-85 and GS-13 customers will migrate to rate GS-85N.

**Figure 2**
**Rate of Return at Present and Proposed Rates**
**GS-85 versus Retail Average ("Hybrid Methodology")**




The conclusion to draw from these graphs is that the GS-85N rate design is not reasonable and over charges the existing GS-85 customers who will now be assigned to this rate. As I will discuss in the next section of my testimony (Rate Design), I am proposing modifications to the Company's proposed GS-85N rate that more reasonably reflect cost of service.

## II. RATE DESIGN ISSUES

**Q. Have you reviewed TEP's design for proposed rate GS-85N?**

A. Yes. This new time-of-day rate will serve current customers on rates GS-13 and GS-85. Rate GS-85 is already a time-of-day rate, while GS-13 is not. The main feature of GS-85N is that it will substantially (and unreasonably) reduce the demand charges in the current GS-85 time-of-day rate, while substantially increasing the energy charges. Table 1 shows a comparison between the present and proposed rates, using the "cost of service" methodology for comparison purposes.

**Table 1**
**Comparison of Present GS-85 to Proposed GS-85N Rate**
**("Cost of Service Methodology" version)**

| | GS-85 | GS-85N | % Change |
|---|---|---|---|
| Customer Charge | 98.01 | 371.88 | 279.4% |
| On-Peak Demand Summer | 7.50 | 3.00 | -60.0% |
| On-Peak Demand Winter | 4.96 | 3.00 | -39.5% |
| Shoulder Demand Summer[1] | 4.96 | 0.00 | -100.0% |
| Off-Peak Demand Summer[1] | 3.75 | 1.00 | -73.3% |
| Off-Peak Demand Winter[1] | 2.48 | 1.00 | -59.7% |
| On-Peak kWh Summer | 0.069587 | 0.129339 | 85.9% |
| On-Peak kWh Winter | 0.065667 | 0.113160 | 72.3% |
| Shoulder kWh | 0.065667 | 0.077613 | 18.2% |
| Off-Peak kWh Summer | 0.061746 | 0.058589 | -5.1% |
| Off-Peak kWh Winter | 0.057826 | 0.042410 | -26.7% |

[1] For GS-85, this charge only applies to kW in excess of 150% of on-peak kW

Though the two rates have somewhat different structures (e.g., the on-peak summer period begins at 2pm for GS-85N and at 1 pm for the existing rate GS-85), the comparison reveals a substantial reduction in the costs that are being recovered through a kW demand charge, versus the time-of-day energy charges. This change is occurring at the same time that the overall increase in proposed by the Company for GS-85 customers is 32.5% under the "cost of service" rate plan.[3] As I will discuss below, these rate design changes are not supported by the Company's cost of service data and are not just and reasonable.

**Q. Would you please explain why TEP's proposed GS-85N rate design is inconsistent with the cost of providing service?**

A. Yes. First, as I discussed previously (Figures 1 and 2), the Company is proposing to charge GS-85N customers above cost of service at proposed rates, based on TEP's average and peak class cost of service study.[4] Second, setting aside the overall revenue requirement being charge to GS-85N customers, the design of the rate itself is inconsistent with the unbundled costs developed in TEP's class cost of service study.

[3] As I noted earlier, GS-85 customers are paying in excess of cost of service at proposed rates.
[4] The disparities between rates and cost of service are likely worse under a more appropriate 4 CP class cost of service study methodology.

As shown in the proposed tariff, the unbundled transmission rate per kWh for GS-85N is $0.007298 per kWh. Baron Exhibit__(SJB-2) is an excerpt from page 3 of 4 of the "Pricing Plan GS-85N" tariff, based on the "cost of service methodology." The identical transmission charge appears in both the "Hybrid" and "Market" tariffs for GS-85N.

**Q. Are transmission charges (other than ancillary services) incurred by TEP based on kWh energy use?**

A. No. TEP incurs these OATT transmission charges based on the 4CP demands of its customers. Though the Company's class cost of service study inappropriately allocates these transmission costs to rate schedules on the basis of the average and peaks demand allocator (instead of a 4CP allocator), the Company at least recognizes that these transmission costs are demand related. Nevertheless, the Company is proposing to collect these costs from rate General Service rate schedules on a uniform kWh basis, regardless of when those kWh are actually consumed. This is not consistent with the nature of the transmission costs and is inconsistent with cost based ratemaking. In addition, it provides inaccurate price signals to customers, who are charged additional transmission costs for off-peak kWh usage that does not result in additional transmission expenses to the Company.

**Q. You indicated that the Company is proposing a uniform transmission rate among all General Service rate schedules. How does this compare to the cost of providing transmission service to these rates?**

A. Table 2 shows a comparison for General Service rate schedules of transmission revenues (based on the uniform $0.007298 per kWh charge) versus the allocated cost providing transmission to these rates from the TEP class cost of service study.

**Table 2**
**Comparison of Transmission Revenues to Cost of Service**
**(Proposed Commercial Class Rates)**

| Rate | Adjusted kWh Sales | Transmission Rate | Transmission Revenue | Transmission Cost | Excess Charge |
|---|---|---|---|---|---|
| GS-10 | 1,763,653,754 | 0.007298 | $ 12,871,145 | $ 13,714,671 | $ (843,526) |
| GS-76N | 136,727,732 | 0.007298 | $ 997,839 | $ 806,751 | $ 191,088 |
| GS-31 | 16,196,892 | 0.007298 | $ 118,205 | $ - | $ 118,205 |
| GS-11 | 60,332,539 | 0.007298 | $ 440,307 | $ 435,189 | $ 5,118 |
| GS-85N | 1,337,468,740 | 0.007298 | $ 9,760,847 | $ 9,189,116 | $ 571,731 |
| Total | 3,314,379,657 | | $ 24,188,343 | $ 24,145,727 | $ 42,616 |

As can be seen, rate schedule GS-85N is being charged $571,731 in excess transmission revenues, compared to the cost of transmission service for the customers. There is no justification for this overcharge and it should be corrected in the TEP rate design for GS-85N.

Q. **Within the GS-85N rate class, how are transmission charges being collected from customers?**

A. Table 3 shows a distribution of transmission revenues by time-of-day period for the proposed GS-85N rate schedules. As can be seen, more than 67% of the transmission revenues are being collected from GS-85N customers during the summer and winter off-peak periods, while only 11.5% of transmission revenues are being collected for summer on-peak usage. This is occurring, despite the fact that TEP pays for transmission service (via the OATT) on the basis of customer usage during the summer on-peak period. Clearly, TEP's proposed uniform kWh transmission rate is widely inconsistent with cost of service and cost causation principals.

**Table 3**
**GS-85N Transmission Cost Rate Recovery by Time-of-Day Period**

| | Summer On-Peak | Summer Shoulder | Summer Off-Peak | Winter On-Peak | Winter Off-Peak | Total[1] |
|---|---|---|---|---|---|---|
| kWh | 153,880,266 | 147,863,362 | 464,852,681 | 131,424,081 | 434,689,156 | 1,332,709,547 |
| Transmission Revenue[2] | $ 1,123,018 | $ 1,079,107 | $ 3,392,495 | $ 959,133 | $ 3,172,361 | 9,726,114 |
| Percent in TOD Period | 11.5% | 11.1% | 34.9% | 9.9% | 32.6% | 100.0% |

[1] Does not include PRS-13 sales
[2] Transmission Rate per kWh: $ 0.007298

Q. **What recommendation do you have to address this problem?**

A. I have recalculated the GS-85N transmission rate based on the allocated cost of providing transmission service to this rate schedule. In addition, I have developed the transmission rate on a $/kW billing demand basis, in recognition of the nature of these costs. This calculation is shown in Table 4 below. I recommend that this rate be used to recover transmission costs for GS-85N. To do so, the uniform $0.007298 charge should be removed from the kWh delivery charges of the proposed rate and the $2.63/kW charge that I calculated in Table 4 should be added to the rate schedule.

**Table 4**
**Development of Transmission Rate for GS-85N**

| Rate | Transmission Cost | kW Billing Determinants[1] | kW Rate |
|---|---|---|---|
| GS-13 | $ 8,391,904 | 3,285,983 | |
| GS-85 | $ 797,212 | 213,046 | |
| Total 85N | $ 9,189,116 | 3,499,029 | $ 2.63 |

[1] Summer and Winter on-peak kW

**Q. Have you identified other problems with the design of the GS-85N rate proposed by TEP?**

A. Yes. In addition to the transmission rate design problem, the Company has also included an insufficient amount of cost in the proposed $3.00/kW GS-85N on-peak demand rate and simultaneously overstated the delivery energy charges. Based on an analysis of the Company's unit cost data from its cost of service study for the "Cost of Service" methodology, the production and distribution demand component revenue requirements for Rate Schedule GS-85N would support an on-peak demand charge in excess of $15 per kW month.[5] For the Hybrid methodology, the on-peak demand cost is in excess of $14 per kW month. Neither of these unit costs include transmission demand costs; they only reflect production demand and distribution demand cost components.

**Q. Are you recommending that the GS-85N on-peak demand charge be set at the $14 to $15 per kW level justified by the Company's unit cost analysis?**

A. No. Though such a rate could be justified based on TEP's own cost of service analysis, I am recommending that the GS-85N on-peak demand charge plus my recommended $2.63 per kW month transmission demand charge be limited to a

[5] For the "Cost of Service" methodology, these demand component revenue requirements are shown in TEP's "Schedule G-6 (Unit Costs) Cost of Service," page 14 of 20.

total of $7.88 per kW month for the "Cost of Service" methodology rate and $8.74 per kW for the "Hybrid" methodology rate. For comparison purposes to the Company's proposed on-peak demand charge of $3.00 per kW (not including transmission charges).

Q. **What is the basis for your recommended $7.88 and $8.74 per kW on-peak demand charges for GS-85N?**

A. Rate Schedule Gs-85N is a new rate that combines customers on existing rates GS-13, GS-85A and GS-85F. These current rates have very different current demand charges. Rate GS-13 has a demand charge of $6.52 per kW, GS-85A has a summer on-peak demand charge of $7.50 and GS-85F has an on-peak summer demand charge of $16.34. As a compromise and to reflect mitigation for GS-13 customers, my recommendation is to set the proposed GS-85n on-peak demand rate at the existing GS-85A on-peak rate, adjusted for the average rate increase to all GS-85N customers. This produces a rate of $7.88 for the "Cost of Service" method and $8.74 per kW for the Hybrid method.

Q. **Have you developed a recommended GS=85N rate, reflecting your proposed rate design changes for the "Cost of Service" methodology?**

A. Yes, Baron Exhibit__(SJB-3), Schedules 1, 2 and 3 shows this analysis. Schedule 1 shows a proof of revenues for GS-85N using the Company's filed rate design. Schedule 2 shows the adjustment to reflect my proposed $2.63 per kW transmission rate (added to the Company's proposed $3.00 on-peak charge) and the removal of the Company's $0.007298 per kWh transmission charge from the GS-85N energy delivery rates. Finally, Schedule 3 shows the GS-85N rate design and proof of revenues using my proposed $7.88 per kW on-peak demand rate. The energy delivery charges have been adjusted to reflect the removal of a portion of the demand related production and distribution costs that are now being shifted from the time-of-day energy charges to the on-peak demand charge.

**Q. Have you developed a similar analysis using the Company's Hybrid methodology?**

A. Yes. Baron Exhibit__(SJB-4) shows the development of the GS-85N rate using the Company's unit cost analysis from the Hybrid methodology case.

## III. TERMINATION COST REGULATORY ASSET CHARGE

**Q. Have you reviewed the cost recovery approach that TEP is recommending for its requested $788 million Termination Cost Regulatory Asset ("TCRA")?**

A. Yes. Although I am not addressing the reasonableness of the recovery of the regulatory asset itself, in the event that the Commission approves the recovery of the Company's regulatory asset charge, it is inappropriate to recover the cost on a uniform kWh basis.[6] As discussed in the Company's testimony, these regulatory asset costs are asserted to be based on an imputed revenue deficiency beginning in 2004. If this is true, it is reasonable to assume that this revenue deficiency was produced by rate schedules in proportion to their individual rate base amounts on which rate of return and income deficiencies are determined, not on kWh energy use. Essentially, the Company's argument for the recovery of the revenue deficiency is equivalent to an argument for an insufficient rate of return on rate base. Therefore, if the recovery of the regulatory asset is approved by the Commission, the TCRA should be allocated to rate schedules on the basis of rate base, not kWh energy use. Baron Exhibit__(SJB-5) shows an

[6] This should not be construed to indicate that Kroger Co. is supporting the TCRAC.

allocation of the TCRA to rate schedules on the basis of a rate base allocator and compares this result to the Company's proposal for a uniform kWh TCRA charge.

**Q. Does that complete your testimony?**

A. Yes.

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103** | **) Docket No. E-01933A-05-0650** |
| **In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona** | **) Docket No. E-01933A-07-0402** |

**EXHIBITS**

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

**J. KENNEDY AND ASSOCIATES, INC.**
**ROSWELL, GEORGIA**

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **In the Matter of the Filing by Tucson Electric** | **) Docket No. E-01933A-05-** |
| **0650** | |
| **Power Company to Amend Decision No. 62103** | **)** |
| **In the Matter of the Application of Tucson Electric** | **)** |
| **Power Company for the Establishment of Just and)** | |
| **Reasonable Rates and Charges Designed to Realize** | **) Docket No. E-01933A-07-** |
| **0402** | |
| **A Reasonable Rate of Return on the Fair Value of** | **)** |
| **Its Operations Throughout the State of Arizona** | **)** |

**EXHIBIT__(SJB-1)**

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 4/81 | 203(B) | KY | Louisville Gas & Electric Co. | Louisville Gas & Electric Co. | Cost-of-service. |
| 4/81 | ER-81-42 | MO | Kansas City Power & Light Co. | Kansas City Power & Light Co. | Forecasting. |
| 6/81 | U-1933 | AZ | Arizona Corporation Commission | Tucson Electric Co. | Forecasting planning. |
| 2/84 | 8924 | KY | Airco Carbide | Louisville Gas & Electric Co. | Revenue requirements, cost-of-service, forecasting, weather normalization. |
| 3/84 | 84-038-U | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Excess capacity, cost-of-service, rate design. |
| 5/84 | 830470-EI | FL | Florida Industrial Power Users' Group | Florida Power Corp. | Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility. |
| 10/84 | 84-199-U | AR | Arkansas Electric Energy Consumers | Arkansas Power and Light Co. | Cost allocation and rate design. |
| 11/84 | R-842651 | PA | Lehigh Valley Power Committee | Pennsylvania Power & Light Co. | Interruptible rates, excess capacity, and phase-in. |
| 1/85 | 85-65 | ME | Airco Industrial Gases | Central Maine Power Co. | Interruptible rate design. |
| 2/85 | I-840381 | PA | Philadelphia Area Industrial Energy Users' Group | Philadelphia Electric Co. | Load and energy forecast. |
| 3/85 | 9243 | KY | Alcan Aluminum Corp., et al. | Louisville Gas & Electric Co. | Economics of completing fossil generating unit. |
| 3/85 | 3498-U | GA | Attorney General | Georgia Power Co. | Load and energy forecasting, generation planning economics. |
| 3/85 | R-842632 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 5/85 | 84-249 | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Cost-of-service, rate design return multipliers. |
| 5/85 | | City of Santa | Chamber of Commerce | Santa Clara Municipal | Cost-of-service, rate design. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 6/85 | 84-768-E-42T | Clara WV | West Virginia Industrial Intervenors | Monongahela Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 6/85 | E-7 Sub 391 | NC | Carolina Industrials (CIGFUR III) | Duke Power Co. | Cost-of-service, rate design, interruptible rate design. |
| 7/85 | 29046 | NY | Industrial Energy Users Association | Orange and Rockland Utilities | Cost-of-service, rate design. |
| 10/85 | 85-043-U | AR | Arkansas Gas Consumers | Arkla, Inc. | Regulatory policy, gas cost-of-service, rate design. |
| 10/85 | 85-63 | ME | Airco Industrial Gases | Central Maine Power Co. | Feasibility of interruptible rates, avoided cost. |
| 2/85 | ER-8507698 | NJ | Air Products and Chemicals | Jersey Central Power & Light Co. | Rate design. |
| 3/85 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Optimal reserve, prudence, off-system sales guarantee plan. |
| 2/86 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Optimal reserve margins, prudence, off-system sales guarantee plan. |
| 3/86 | 85-299U | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Cost-of-service, rate design, revenue distribution. |
| 3/86 | 85-726-EL-AIR | OH | Industrial Electric Consumers Group | Ohio Power Co. | Cost-of-service, rate design, interruptible rates. |
| 5/86 | 86-081-E-GI | WV | West Virginia Energy Users Group | Monongahela Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 8/86 | E-7 Sub 408 | NC | Carolina Industrial Energy Consumers | Duke Power Co. | Cost-of-service, rate design, interruptible rates. |
| 10/86 | U-17378 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Excess capacity, economic analysis of purchased power. |
| 12/86 | 38063 | IN | Industrial Energy Consumers | Indiana & Michigan Power Co. | Interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 3/87 | EL-86-53-001 EL-86-57-001 | Federal Energy Regulatory Commission (FERC) | Louisiana Public Service Commission Staff | Gulf States Utilities, Southern Co. | Cost/benefit analysis of unit power sales contract. |
| 4/87 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Load forecasting and imprudence damages, River Bend Nuclear unit. |
| 5/87 | 87-023-E-C | WV | Airco Industrial Gases | Monongahela Power Co. | Interruptible rates. |
| 5/87 | 87-072-E-G1 | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims. |
| 5/87 | 86-524-E-SC | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Economic dispatching of pumped storage hydro unit. |
| 5/87 | 9781 | KY | Kentucky Industrial Energy Consumers | Louisville Gas & Electric Co. | Analysis of impact of 1986 Tax Reform Act. |
| 6/87 | 3673-U | GA | Georgia Public Service Commission | Georgia Power Co. | Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning. |
| 6/87 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Phase-in plan for River Bend Nuclear unit. |
| 7/87 | 85-10-22 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Methodology for refunding rate moderation fund. |
| 8/87 | 3673-U | GA | Georgia Public Service Commission | Georgia Power Co. | Test year sales and revenue forecast. |
| 9/87 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Excess capacity, reliability of generating system. |
| 10/87 | R-870651 | PA | Duquesne Industrial Intervenors | Duquesne Light Co. | Interruptible rate, cost-of-service, revenue allocation, rate design. |
| 10/87 | I-860025 | PA | Pennsylvania Industrial Intervenors | | Proposed rules for cogeneration, avoided cost, rate recovery. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 10/87 | E-015/<br>GR-87-223 | MN | Taconite<br>Intervenors | Minnesota Power<br>& Light Co. | Excess capacity, power and<br>cost-of-service, rate design. |
| 10/87 | 8702-EI | FL | Occidental Chemical<br>Corp. | Florida Power Corp. | Revenue forecasting, weather<br>normalization. |
| 12/87 | 87-07-01 | CT | Connecticut Industrial<br>Energy Consumers | Connecticut Light<br>Power Co. | Excess capacity, nuclear plant<br>phase-in. |
| 3/88 | 10064 | KY | Kentucky Industrial<br>Energy Consumers | Louisville Gas &<br>Electric Co. | Revenue forecast, weather<br>normalization rate treatment<br>of cancelled plant. |
| 3/88 | 87-183-TF | AR | Arkansas Electric<br>Consumers | Arkansas Power &<br>Light Co. | Standby/backup electric rates. |
| 5/88 | 870171C001 | PA | GPU Industrial<br>Intervenors | Metropolitan<br>Edison Co. | Cogeneration deferral<br>mechanism, modification of energy<br>cost recovery (ECR). |
| 6/88 | 870172C005 | PA | GPU Industrial<br>Intervenors | Pennsylvania<br>Electric Co. | Cogeneration deferral<br>mechanism, modification of energy<br>cost recovery (ECR). |
| 7/88 | 88-171-<br>EL-AIR<br>88-170-<br>EL-AIR<br>Interim Rate Case | OH | Industrial Energy<br>Consumers | Cleveland Electric/<br>Toledo Edison | Financial analysis/need for<br>interim rate relief. |
| 7/88 | Appeal<br>of PSC | 19th<br>Judicial<br>Docket<br>U-17282 | Louisiana Public<br>Service Commission<br>Circuit<br>Court of Louisiana | Gulf States<br>Utilities | Load forecasting, imprudence<br>damages. |
| 11/88 | R-880989 | PA | United States<br>Steel | Carnegie Gas | Gas cost-of-service, rate<br>design. |
| 11/88 | 88-171-<br>EL-AIR<br>88-170-<br>EL-AIR | OH | Industrial Energy<br>Consumers | Cleveland Electric/<br>Toledo Edison.<br>General Rate Case. | Weather normalization of<br>peak loads, excess capacity,<br>regulatory policy. |
| 3/89 | 870216/283<br>284/286 | PA | Armco Advanced<br>Materials Corp.,<br>Allegheny Ludlum<br>Corp. | West Penn Power Co. | Calculated avoided capacity,<br>recovery of capacity payments. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 8/89 | 8555 | TX | Occidental Chemical Corp. | Houston Lighting & Power Co. | Cost-of-service, rate design. |
| 8/89 | 3840-U | GA | Georgia Public Service Commission | Georgia Power Co. | Revenue forecasting, weather normalization. |
| 9/89 | 2087 | NM | Attorney General of New Mexico | Public Service Co. of New Mexico | Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting. |
| 10/89 | 2262 | NM | New Mexico Industrial Energy Consumers | Public Service Co. of New Mexico | Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost. |
| 11/89 | 38728 | IN | Industrial Consumers for Fair Utility Rates | Indiana Michigan Power Co. | Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates. |
| 1/90 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Jurisdictional cost allocation, O&M expense analysis. |
| 5/90 | 890366 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Non-utility generator cost recovery. |
| 6/90 | R-901609 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Allocation of QF demand charges in the fuel cost, cost-of-service, rate design. |
| 9/90 | 8278 | MD | Maryland Industrial Group | Baltimore Gas & Electric Co. | Cost-of-service, rate design, revenue allocation. |
| 12/90 | U-9346 Rebuttal | MI | Association of Businesses Advocating Tariff Equity | Consumers Power Co. | Demand-side management, environmental externalities. |
| 12/90 | U-17282 Phase IV | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Revenue requirements, jurisdictional allocation. |
| 12/90 | 90-205 | ME | Airco Industrial Gases | Central Maine Power Co. | Investigation into interruptible service and rates. |
| 1/91 | 90-12-03 Interim | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Interim rate relief, financial analysis, class revenue allocation. |

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**Stephen J. Baron**
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| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 5/91 | 90-12-03 Phase II | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Revenue requirements, cost-of-service, rate design, demand-side management. |
| 8/91 | E-7, SUB SUB 487 | NC | North Carolina Industrial Energy Consumers | Duke Power Co. | Revenue requirements, cost allocation, rate design, demand-side management. |
| 8/91 | 8341 Phase I | MD | Westvaco Corp. | Potomac Edison Co. | Cost allocation, rate design, 1990 Clean Air Act Amendments. |
| 8/91 | 91-372 EL-UNC | OH | Armco Steel Co., L.P. | Cincinnati Gas & Electric Co. | Economic analysis of cogeneration, avoid cost rate. |
| 9/91 | P-910511 P-910512 | PA | Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group | West Penn Power Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 9/91 | 91-231 -E-NC | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 10/91 | 8341 - Phase II | MD | Westvaco Corp. | Potomac Edison Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 10/91 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Results of comprehensive management audit. |
| Note: No testimony was prefiled on this. | | | | | |
| 11/91 | U-17949 Subdocket A | LA | Louisiana Public Service Commission Staff | South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co. | Analysis of South Central Bell's restructuring and |
| 12/91 | 91-410-EL-AIR | OH | Armco Steel Co., Air Products & Chemicals, Inc. | Cincinnati Gas & Electric Co. | Rate design, interruptible rates. |
| 12/91 | P-880286 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Evaluation of appropriate avoided capacity costs - QF projects. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
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| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 1/92 | C-913424 | PA | Duquesne Interruptible Complainants | Duquesne Light Co. | Industrial interruptible rate. |
| 6/92 | 92-02-19 | CT | Connecticut Industrial Energy Consumers | Yankee Gas Co. | Rate design. |
| 8/92 | 2437 | NM | New Mexico Industrial Intervenors | Public Service Co. of New Mexico | Cost-of-service. |
| 8/92 | R-00922314 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Cost-of-service, rate design, energy cost rate. |
| 9/92 | 39314 | ID | Industrial Consumers for Fair Utility Rates | Indiana Michigan Power Co. | Cost-of-service, rate design, energy cost rate, rate treatment. |
| 10/92 | M-00920312 C-007 | PA | The GPU Industrial Intervenors | Pennsylvania Electric Co. | Cost-of-service, rate design, energy cost rate, rate treatment. |
| 12/92 | U-17949 | LA | Louisiana Public Service Commission Staff | South Central Bell Co. | Management audit. |
| 12/92 | R-00922378 | PA | Armco Advanced Materials Co. The WPP Industrial Intervenors | West Penn Power Co. | Cost-of-service, rate design, energy cost rate, $SO_2$ allowance rate treatment. |
| 1/93 | 8487 | MD | The Maryland Industrial Group | Baltimore Gas & Electric Co. | Electric cost-of-service and rate design, gas rate design (flexible rates). |
| 2/93 | E002/GR-92-1185 | MN | North Star Steel Co. Praxair, Inc. | Northern States Power Co. | Interruptible rates. |
| 4/93 | EC92 21000 ER92-806-000 (Rebuttal) | Federal Energy Regulatory Commission | Louisiana Public Service Commission Staff | Gulf States Utilities/Entergy agreement. | Merger of GSU into Entergy System; impact on system |
| 7/93 | 93-0114-E-C | WV | Airco Gases | Monongahela Power Co. | Interruptible rates. |
| 8/93 | 930759-EG | FL | Florida Industrial Power Users' Group | Generic - Electric Utilities | Cost recovery and allocation of DSM costs. |
| 9/93 | M-009 30406 | PA | Lehigh Valley Power Committee | Pennsylvania Power & Light Co. | Ratemaking treatment of off-system sales revenues. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 11/93 | 346 | KY | Kentucky Industrial Utility Customers | Generic - Gas Utilities | Allocation of gas pipeline transition costs - FERC Order 636. |
| 12/93 | U-17735 | LA | Louisiana Public Service Commission Staff | Cajun Electric Power Cooperative | Nuclear plant prudence, forecasting, excess capacity. |
| 4/94 | E-015/ GR-94-001 | MN | Large Power Intervenors | Minnesota Power Co. | Cost allocation, rate design, rate phase-in plan. |
| 5/94 | U-20178 | LA | Louisiana Public Service Commission | Louisiana Power & Light Co. | Analysis of least cost integrated resource plan and demand-side management program. |
| 7/94 | R-00942986 | PA | Armco, Inc.; West Penn Power Industrial Intervenors | West Penn Power Co. | Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense. |
| 7/94 | 94-0035-E-42T | WV | West Virginia Energy Users Group | Monongahela Power Co. | Cost-of-service, allocation of rate increase, and rate design. |
| 8/94 | EC94 13-000 | Federal Energy Regulatory Commission | Louisiana Public Service Commission | Gulf States Utilities/Entergy | Analysis of extended reserve shutdown units and violation of system agreement by Entergy. |
| 9/94 | R-00943 081 R-00943 081C0001 | PA | Lehigh Valley Power Committee | Pennsylvania Public Utility Commission | Analysis of interruptible rate terms and conditions, availability. |
| 9/94 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Evaluation of appropriate avoided cost rate. |
| 9/94 | U-19904 | LA | Louisiana Public Service Commission | Gulf States Utilities | Revenue requirements. |
| 10/94 | 5258-U | GA | Georgia Public Service Commission | Southern Bell Telephone & Telegraph Co. | Proposals to address competition in telecommunication markets. |
| 11/94 | EC94-7-000 ER94-898-000 | FERC | Louisiana Public Service Commission | El Paso Electric and Central and Southwest | Merger economics, transmission equalization hold harmless proposals. |
| 2/95 | 941-430EG | CO | CF&I Steel, L.P. | Public Service Company of Colorado | Interruptible rates, cost-of-service. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 4/95 | R-00943271 | PA | PP&L Industrial Customer Alliance | Pennsylvania Power & Light Co. | Cost-of-service, allocation of rate increase, rate design, interruptible rates. |
| 6/95 | C-00913424 C-00946104 | PA | Duquesne Interruptible Complainants | Duquesne Light Co. | Interruptible rates. |
| 8/95 | ER95-112 -000 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. | Open Access Transmission Tariffs - Wholesale. |
| 10/95 | U-21485 | LA | Louisiana Public Service Commission | Gulf States Utilities Company | Nuclear decommissioning, revenue requirements, capital structure. |
| 10/95 | ER95-1042 -000 | FERC | Louisiana Public Service Commission | System Energy Resources, Inc. | Nuclear decommissioning, revenue requirements. |
| 10/95 | U-21485 | LA | Louisiana Public Service Commission | Gulf States Utilities Co. | Nuclear decommissioning and cost of debt capital, capital structure. |
| 11/95 | I-940032 | PA | Industrial Energy Consumers of Pennsylvania | State-wide - all utilities | Retail competition issues. |
| 7/96 | U-21496 | LA | Louisiana Public Service Commission | Central Louisiana Electric Co. | Revenue requirement analysis. |
| 7/96 | 8725 | MD | Maryland Industrial Group | Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co. | Ratemaking issues associated with a Merger. |
| 8/96 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Revenue requirements. |
| 9/96 | U-22092 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Decommissioning, weather normalization, capital structure. |
| 2/97 | R-973877 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Co. | Competitive restructuring policy issues, stranded cost, transition charges. |
| 6/97 | Civil Action No. 94-11474 | US Bankruptcy Court Middle District of Louisiana | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Confirmation of reorganization plan; analysis of rate paths produced by competing plans. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 6/97 | R-973953 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 6/97 | 8738 | MD | Maryland Industrial Group | Generic | Retail competition issues |
| 7/97 | R-973954 | PA | PP&L Industrial Customer Alliance | Pennsylvania Power & Light Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 10/97 | 97-204 | KY | Alcan Aluminum Corp. Southwire Co. | Big River Electric Corp. | Analysis of cost of service issues - Big Rivers Restructuring Plan |
| 10/97 | R-974008 | PA | Metropolitan Edison Industrial Users | Metropolitan Edison Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 10/97 | R-974009 | PA | Pennsylvania Electric Industrial Customer | Pennsylvania Electric Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 11/97 | U-22491 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Decommissioning, weather normalization, capital structure. |
| 11/97 | P-971265 | PA | Philadelphia Area Industrial Energy Users Group | Enron Energy Services Power, Inc./ PECO Energy | Analysis of Retail Restructuring Proposal. |
| 12/97 | R-973981 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 12/97 | R-974104 | PA | Duquesne Industrial Intervenors | Duquesne Light Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 3/98 (Allocated Stranded Cost Issues) | U-22092 | LA | Louisiana Public Service Commission | Gulf States Utilities Co. | Retail competition, stranded cost quantification. |
| 3/98 | U-22092 | | Louisiana Public Service Commission | Gulf States Utilities, Inc. | Stranded cost quantification, restructuring issues. |
| 9/98 | U-17735 | | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Revenue requirements analysis, weather normalization. |
| 12/98 | 8794 | MD | Maryland Industrial Group and | Baltimore Gas and Electric Co. | Electric utility restructuring, stranded cost recovery, rate |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | Millennium Inorganic Chemicals Inc. | | unbundling. |
| 12/98 | U-23358 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, weather normalization, Entergy System Agreement. |
| 5/99 (Cross-Answering Testimony) | EC-98-40-000 | FERC | Louisiana Public Service Commission | American Electric Power Co. & Central South West Corp. | Merger issues related to market power mitigation proposals. |
| 5/99 (Response Testimony) | 98-426 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. | Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services. |
| 6/99 | 98-0452 | WV | West Virginia Energy Users Group | Appalachian Power, Monongahela Power, & Potomac Edison Companies | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 7/99 | 99-03-35 | CT | Connecticut Industrial \Energy Consumers | United Illuminating Company | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 7/99 | Adversary Proceeding No. 98-1065 | U.S. Bankruptcy Court | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Motion to dissolve preliminary injunction. |
| 7/99 | 99-03-06 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 10/99 | U-24182 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, weather normalization, Entergy System Agreement. |
| 12/99 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Ananlysi of Proposed Contract Rates, Market Rates. |
| 03/00 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Evaluation of Cooperative Power Contract Elections |
| 03/00 | 99-1658-EL-ETP | OH | AK Steel Corporation | Cincinnati Gas & Electric Co. | Electric utility restructuring, stranded cost recovery, rate Unbundling. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 08/00 | 98-0452 E-GI | WVA | West Virginia Energy Users Group | Appalachian Power Co. American Electric Co. | Electric utility restructuring rate unbundling. |
| 08/00 | 00-1050 E-T 00-1051-E-T | WVA | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Electric utility restructuring rate unbundling. |
| 10/00 | SOAH 473-00-1020 PUC 2234 | TX | The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities | TXU, Inc. | Electric utility restructuring rate unbundling. |
| 12/00 | U-24993 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, revenue requirements. |
| 12/00 | EL00-66-000 & ER00-2854 EL95-33-002 | LA | Louisiana Public Service Commission | Entergy Services Inc. | Inter-Company System Agreement: Modifications for retail competition, interruptible load. |
| 04/01 | U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Jurisdictional Business Separation - Texas Restructuring Plan |
| 10/01 | 14000-U | GA | Georgia Public Service Commission Adversary Staff | Georgia Power Co. | Test year revenue forecast. |
| 11/01 | U-25687 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning requirements transmission revenues. |
| 11/01 | U-25965 | LA | Louisiana Public Service Commission | Generic | Independent Transmission Company ("Transco"). RTO rate design. |
| 03/02 | 001148-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design, resource planning and demand side management. |
| 06/02 | U-25965 | LA | Louisiana Public Service Commission | Entergy Gulf States Entergy Louisiana | RTO Issues |
| 07/02 | U-21453 | LA | Louisiana Public Service Commission | SWEPCO, AEP | Jurisdictional Business Sep. - Texas Restructuring Plan. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 08/02 | U-25888 | LA | Louisiana Public Service Commission | Entergy Louisiana, Inc. Entergy Gulf States, Inc. | Modifications to the Inter-Company System Agreement, Production Cost Equalization. |
| 08/02 | EL01-88-000 | FERC | Louisiana Public Service Commission | Entergy Services Inc. and the Entergy Operating Companies | Modifications to the Inter-Company System Agreement, Production Cost Equalization. |
| 11/02 | 02S-315EG | CO | CF&I Steel & Climax Molybdenum Co. | Public Service Co. of Colorado | Fuel Adjustment Clause |
| 01/03 | U-17735 | LA | Louisiana Public Service Commission | Louisiana Coops | Contract Issues |
| 02/03 | 02S-594E | CO | Cripple Creek and Victor Gold Mining Co. | Aquila, Inc. | Revenue requirements, purchased power. |
| 04/03 | U-26527 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Weather normalization, power purchase expenses, System Agreement expenses. |
| 11/03 | ER03-753-000 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Proposed modifications to System Agreement Tariff MSS-4. |
| 11/03 | ER03-583-000 ER03-583-001 ER03-583-002<br>ER03-681-000, ER03-681-001<br>ER03-682-000, ER03-682-001 ER03-682-002 | FERC | Louisiana Public Service Commission | Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc. | Evaluation of Wholesale Purchased Power Contracts. |
| 12/03 | U-27136 | LA | Louisiana Public Service Commission | Entergy Louisiana, Inc. | Evaluation of Wholesale Purchased Power Contracts. |
| 01/04 | E-01345-03-0437 | AZ | Kroger Company | Arizona Public Service Co. | Revenue allocation rate design. |
| 02/04 | 00032071 | PA | Duquesne Industrial Intervenors | Duquesne Light Company | Provider of last resort issues. |
| 03/04 | 03A-436E | CO | CF&I Steel, LP and Climax Molybedenum | Public Service Company of Colorado | Purchased Power Adjustment Clause. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 04/04 | 2003-00433<br>2003-00434 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co.<br>Kentucky Utilities Co. | Cost of Service Rate Design |
| 0-6/04 | 03S-539E | CO | Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co. | Aquila, Inc. | Cost of Service, Rate Design Interruptible Rates |
| 06/04 | R-00049255 | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues and transmission service charge. |
| 10/04 | 04S-164E | CO | CF&I Steel Company, Climax Mines | Public Service Company of Colorado | Cost of service, rate design, Interruptible Rates. |
| 03/05 | Case No.<br>2004-00426<br>Case No.<br>2004-00421 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Utilities<br>Louisville Gas & Electric Co. | Environmental cost recovery. |
| 06/05 | 050045-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design |
| 07/05 | U-28155 | LA | Louisiana Public Service Commission Staff | Entergy Louisiana, Inc.<br>Entergy Gulf States, Inc. | Independent Coordinator of Transmission – Cost/Benefit |
| 09/05 | Case Nos.<br>05-0402-E-CN<br>05-0750-E-PC | WVA | West Virginia Energy Users Group | Mon Power Co.<br>Potomac Edison Co. | Environmental cost recovery, Securitization, Financing Order |
| 01/06 | 2005-00341 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Power Company | Cost of service, rate design, transmission expenses, Congestion Cost Recovery Mechanism |
| 03/06 | U-22092 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. | Separation of EGSI into Texas and Louisiana Companies. |
| 04/06 | U-25116 | LA | Louisiana Public Service Commission Staff | Entergy Louisiana, Inc. | Transmission Prudence Investigation |
| 06/06 | R-00061346<br>C0001-0005 | PA | Duquesne Industrial Intervenors & IECPA | Duquesne Light Co. | Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues |
| 06/06 | R-00061366<br>R-00061367<br>P-00062213<br>P-00062214 | | Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance | Metropolitan Edison Co.<br>Pennsylvania Electric Co. | Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues |
| 07/06 | U-22092<br>Sub-J | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. | Separation of EGSI into Texas and Louisiana Companies. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 07/06 | Case No. 2006-00130 Case No. 2006-00129 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Utilities Louisville Gas & Electric Co. | Environmental cost recovery. |
| 08/06 | Case No. PUE-2006-00065 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment |
| 11/06 | Doc. No. 97-01-15RE02 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power United Illuminating | Rate unbundling issues. |
| 01/07 | Case No. 06-0960-E-42T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Retail Cost of Service Revenue apportionment |
| 03/07 | U-29764 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. Entergy Louisiana, LLC | Implementation of FERC Decision Jurisdictional & Rate Class Allocation |
| 05/07 | Case No. 07-63-EL-UNC | OH | Ohio Energy Group | Ohio Power, Columbus Southern Power | Environmental Surcharge Rate Design |
| 05/07 | R-00049255 Remand | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues and transmission service charge. |
| 06/07 | R-00072155 | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues. |
| 07/07 | Doc. No. 07F-037E | CO | Gateway Canyons LLC | Grand Valley Power Coop. | Distribution Line Cost Allocation |
| 09/07 | Doc. No. 05-UR-103 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Electric Power Co. | Cost of Service, rate design, tariff issues, Interruptible rates. |
| 11/07 | ER07-682-000 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues. |
| 1/08 | Doc. No. 20000-277-ER-07 | WY | Cimarex Energy Company | Rocky Mountain Power (PacifiCorp) | Vintage Pricing, Marginal Cost Pricing Projected Test Year |
| 1/08 | Case No. 07-551 | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of March 2008**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 2/08 | ER07-956 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |
| 2/08 | Doc No. P-00072342 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Default Service Plan issues. |

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

**In the Matter of the Filing by Tucson Electric ) Docket No. E-01933A-05-0650**
**Power Company to Amend Decision No. 62103 )**

**In the Matter of the Application of Tucson Electric )**
**Power Company for the Establishment of Just and)**
**Reasonable Rates and Charges Designed to Realize ) Docket No. E-01933A-07-0402**
**A Reasonable Rate of Return on the Fair Value of )**
**Its Operations Throughout the State of Arizona )**

**EXHIBIT__(SJB-2)**

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

The Energy People

# Pricing Plan GS-85N
# General Service Time-of-Use

| | SUMMER (May – October) | WINTER (November – April) |
|---|---|---|
| On-peak | $0.043901 | $0.039219 |
| Shoulder-peak | $0.027985 | N/A |
| Off-peak | $0.022651 | $0.017969 |

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003293 per kWh

System Benefits $0.000443 per kWh

Transmission $0.007298 per kWh

Transmission Ancillary Services

- System Control & Dispatch $0.000099 per kWh
- Reactive Supply and Voltage Control $0.000390 per kWh
- Regulation and Frequency Response $0.000377 per kWh
- Spinning Reserve Service $0.001024 per kWh
- Supplemental Reserve Service $0.000167 per kWh
- Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000171 per kWh

Fuel and Purchased Power:

| | SUMMER (May – October) | WINTER (November – April) |
|---|---|---|
| On-peak | $0.072176 | $0.060679 |
| Shoulder-peak | $0.036366 | N/A |
| Off-peak | $0.022676 | $0.011179 |

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **In the Matter of the Filing by Tucson Electric** | **) Docket No. E-01933A-05-** |
| **0650** | |
| **Power Company to Amend Decision No. 62103** | **)** |
| | |
| **In the Matter of the Application of Tucson Electric** | **)** |
| **Power Company for the Establishment of Just and)** | |
| **Reasonable Rates and Charges Designed to Realize** | **) Docket No. E-01933A-07-** |
| **0402** | |
| **A Reasonable Rate of Return on the Fair Value of** | **)** |
| **Its Operations Throughout the State of Arizona** | **)** |

**EXHIBIT__(SJB-3)**

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

Exhibit ___(SJB-3)
Schedule 1

**TUCSON ELECTRIC POWER**
**LARGE GENERAL SERVICE TIME OF USE - LGS-85N**
Cost of Service Methodology

| Line No. | | | New Billing Determinants | TEP Proposed Rate | Proposed Revenue |
|---|---|---|---|---|---|
| 1 | Customer Charge | | 7,812 | $371.88 | $2,905,127 |
| | **DELIVERY DEMAND CHARGES** | | | | |
| | Summer Demand | | | | |
| 2 | On Peak kW | | 1,753,711 | $3.00 | $5,261,134 |
| 3 | Off Peak kW | | 1,753,711 | $1.00 | $1,751,958 |
| | Winter Demand | | | | |
| 4 | On Peak kW | | 1,732,383 | $3.00 | $5,197,150 |
| 5 | Off Peak kW | | 1,732,383 | $1.00 | $1,730,651 |
| | **DELIVERY ENERGY CHARGES** | | | | |
| | Summer | | | | |
| 6 | On Peak kWhs | | 153,880,266 | $0.056992 | $8,769,912 |
| 7 | Off Peak kWhs | | 464,852,681 | $0.035742 | $16,614,667 |
| 8 | Shoulder Peak kWhs | | 147,863,362 | $0.041076 | $6,073,625 |
| | Winter | | | | |
| 9 | On Peak kWhs | | 199,664,087 | $0.052310 | $10,444,345 |
| 10 | Off Peak kWhs | | 366,449,150 | $0.031060 | $11,381,757 |
| 11 | Revenue Delivery Charges | | | | $70,130,325 |
| 12 | Generation Capacity | | 1,332,709,547 | 0.000171 | 227,813 |
| 13 | **FUEL & PURCHASED POWER** | | | | |
| | Summer | | | | |
| | On Peak kWhs | | 153,880,266 | 0.072176 | 11,106,525 |
| | Off Peak kWhs | | 464,852,681 | 0.022676 | 10,541,190 |
| | Shoulder Peak kWhs | | 147,863,362 | 0.036366 | 5,377,217 |
| | Winter | | | | |
| | On Peak kWhs | | 199,664,087 | 0.060679 | 12,115,445 |
| | Off Peak kWhs | | 366,449,150 | 0.011179 | 4,096,586 |
| 14 | TOTAL REVENUE | | | | $113,595,101 |
| 15 | **TOTAL LGS-85N** | kWh | 1,332,709,547 | | |
| 16 | | Cust | 651 | | |

Exhibit ___(SJB-3)
Schedule 2

**TUCSON ELECTRIC POWER**
**LARGE GENERAL SERVICE TIME OF USE - LGS-85N**
Cost of Service Methodology

| Line No. | | | New Billing Determinants | Proposed Rate | Proposed Revenue |
|---|---|---|---|---|---|
| 1 | Customer Charge | | 7,812 | $371.88 | $2,905,127 |
| | **DELIVERY DEMAND CHARGES** | | | | |
| | Summer Demand | | | | |
| 2 | On Peak kW | | 1,753,711 | $5.63 | $9,873,395 |
| 3 | Off Peak kW | | 1,753,711 | $1.00 | $1,751,958 |
| | Winter Demand | | | | |
| 4 | On Peak kW | | 1,732,383 | $5.63 | $9,753,318 |
| 5 | Off Peak kW | | 1,732,383 | $1.00 | $1,730,651 |
| | **DELIVERY ENERGY CHARGES** | | | | |
| | Summer | | | | |
| 6 | On Peak kWhs | | 153,880,266 | $0.049694 | $7,646,894 |
| 7 | Off Peak kWhs | | 464,852,681 | $0.028444 | $13,222,172 |
| 8 | Shoulder Peak kWhs | | 147,863,362 | $0.033778 | $4,994,518 |
| | Winter | | | | |
| 9 | On Peak kWhs | | 199,664,087 | $0.045012 | $8,987,196 |
| 10 | Off Peak kWhs | | 366,449,150 | $0.023762 | $8,707,411 |
| 11 | Revenue Delivery Charges | | | | $69,572,639 |
| 12 | Generation Capacity | | 1,332,709,547 | 0.000171 | 227,813 |
| 13 | **FUEL & PURCHASED POWER** | | | | |
| | Summer | | | | |
| | On Peak kWhs | | 153,880,266 | 0.072176 | 11,106,525 |
| | Off Peak kWhs | | 464,852,681 | 0.022676 | 10,541,190 |
| | Shoulder Peak kWhs | | 147,863,362 | 0.036366 | 5,377,217 |
| | Winter | | | | |
| | On Peak kWhs | | 199,664,087 | 0.060679 | 12,115,445 |
| | Off Peak kWhs | | 366,449,150 | 0.011179 | 4,096,586 |
| 14 | TOTAL REVENUE | | | | $113,037,415 |
| 15 | **TOTAL LGS-85N** | kWh | 1,332,709,547 | | |
| 16 | | Cust | 651 | | |

Exhibit ___(SJB-3)
Schedule 3

**TUCSON ELECTRIC POWER**
**LARGE GENERAL SERVICE TIME OF USE - LGS-85N**
Cost of Service Methodology

| Line No. | | | New Billing Determinants | Proposed Rate | Proposed Revenue |
|---|---|---|---|---|---|
| 1 | Customer Charge | | 7,812 | $371.88 | $2,905,127 |
| | **DELIVERY DEMAND CHARGES** | | | | |
| | Summer Demand | | | | |
| 2 | On Peak kW | | 1,753,711 | $7.88 | $13,819,246 |
| 3 | Off Peak kW | | 1,753,711 | $1.00 | $1,751,958 |
| | Winter Demand | | | | |
| 4 | On Peak kW | | 1,732,383 | $7.88 | $13,651,180 |
| 5 | Off Peak kW | | 1,732,383 | $1.00 | $1,730,651 |
| | **DELIVERY ENERGY CHARGES** | | | | |
| | Summer | | | | |
| 6 | On Peak kWhs | | 153,880,266 | $0.043808 | $6,741,226 |
| 7 | Off Peak kWhs | | 464,852,681 | $0.022558 | $10,486,264 |
| 8 | Shoulder Peak kWhs | | 147,863,362 | $0.027892 | $4,124,262 |
| | Winter | | | | |
| 9 | On Peak kWhs | | 199,664,087 | $0.039126 | $7,812,066 |
| 10 | Off Peak kWhs | | 366,449,150 | $0.017876 | $6,550,661 |
| 11 | Revenue Delivery Charges | | | | $69,572,639 |
| 12 | Generation Capacity | | 1,332,709,547 | 0.000171 | 227,813 |
| 13 | **FUEL & PURCHASED POWER** | | | | |
| | Summer | | | | |
| | On Peak kWhs | | 153,880,266 | 0.072176 | 11,106,525 |
| | Off Peak kWhs | | 464,852,681 | 0.022676 | 10,541,190 |
| | Shoulder Peak kWhs | | 147,863,362 | 0.036366 | 5,377,217 |
| | Winter | | | | |
| | On Peak kWhs | | 199,664,087 | 0.060679 | 12,115,445 |
| | Off Peak kWhs | | 366,449,150 | 0.011179 | 4,096,586 |
| 14 | TOTAL REVENUE | | | | $113,037,415 |
| 15 | **TOTAL LGS-85N** | kWh | 1,332,709,547 | | |
| 16 | | Cust | 651 | | |

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103** | **) Docket No. E-01933A-05-0650** |
| **In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona** | **) Docket No. E-01933A-07-0402** |

**EXHIBIT__(SJB-4)**

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

Exhibit ___(SJB-4)
Schedule 1

**TUCSON ELECTRIC POWER**
**LARGE GENERAL SERVICE TIME OF USE - LGS-85N**
Hybrid Methodology

| Line No. | | | New Billing Determinants | TEP Proposed Rate | Proposed Revenue |
|---|---|---|---|---|---|
| 1 | Customer Charge | | 7,812 | $371.88 | $2,905,127 |
| | **DELIVERY DEMAND CHARGES** | | | | |
| | Summer Demand | | | | |
| 2 | On Peak kW | | 1,753,711 | $3.00 | $5,261,134 |
| 3 | Off Peak kW | | 1,753,711 | $1.00 | $1,751,958 |
| | Winter Demand | | | | |
| 4 | On Peak kW | | 1,732,383 | $3.00 | $5,197,150 |
| 5 | Off Peak kW | | 1,732,383 | $1.00 | $1,730,651 |
| | **DELIVERY ENERGY CHARGES** | | | | |
| | Summer | | | | |
| 6 | On Peak kWhs | | 153,880,266 | $0.056992 | $8,769,912 |
| 7 | Off Peak kWhs | | 464,852,681 | $0.035742 | $16,614,667 |
| 8 | Shoulder Peak kWhs | | 147,863,362 | $0.041076 | $6,073,625 |
| | Winter | | | | |
| 9 | On Peak kWhs | | 199,664,087 | $0.052310 | $10,444,345 |
| 10 | Off Peak kWhs | | 366,449,150 | $0.031060 | $11,381,757 |
| 11 | Revenue Delivery Charges | | | | $70,130,325 |
| 12 | Generation Capacity | | 1,332,709,547 | 0.000208 | 277,770 |
| 13 | **FUEL & PURCHASED POWER** | | | | |
| | Summer | | | | |
| | On Peak kWhs | | 153,880,266 | 0.081447 | 12,533,078 |
| | Off Peak kWhs | | 464,852,681 | 0.031947 | 14,850,625 |
| | Shoulder Peak kWhs | | 147,863,362 | 0.045637 | 6,747,990 |
| | Winter | | | | |
| | On Peak kWhs | | 199,664,087 | 0.069950 | 13,966,439 |
| | Off Peak kWhs | | 366,449,150 | 0.020450 | 7,493,767 |
| 14 | TOTAL REVENUE | | | | $125,999,994 |
| 15 | **TOTAL LGS-85N** | kWh | 1,332,709,547 | | |
| 16 | | Cust | 651 | | |

Exhibit ___(SJB-4)
Schedule 2

**TUCSON ELECTRIC POWER**
**LARGE GENERAL SERVICE TIME OF USE - LGS-85N**
Hybrid Methodology

| Line No. | | | New Billing Determinants | Proposed Rate | Proposed Revenue |
|---|---|---|---|---|---|
| 1 | Customer Charge | | 7,812 | $371.88 | $2,905,127 |
| | **DELIVERY DEMAND CHARGES** | | | | |
| | Summer Demand | | | | |
| 2 | On Peak kW | | 1,753,711 | $5.63 | $9,873,395 |
| 3 | Off Peak kW | | 1,753,711 | $1.00 | $1,751,958 |
| | Winter Demand | | | | |
| 4 | On Peak kW | | 1,732,383 | $5.63 | $9,753,318 |
| 5 | Off Peak kW | | 1,732,383 | $1.00 | $1,730,651 |
| | **DELIVERY ENERGY CHARGES** | | | | |
| | Summer | | | | |
| 6 | On Peak kWhs | | 153,880,266 | $0.049694 | $7,646,894 |
| 7 | Off Peak kWhs | | 464,852,681 | $0.028444 | $13,222,172 |
| 8 | Shoulder Peak kWhs | | 147,863,362 | $0.033778 | $4,994,518 |
| | Winter | | | | |
| 9 | On Peak kWhs | | 199,664,087 | $0.045012 | $8,987,196 |
| 10 | Off Peak kWhs | | 366,449,150 | $0.023762 | $8,707,411 |
| 11 | Revenue Delivery Charges | | | | $69,572,639 |
| 12 | Generation Capacity | | 1,332,709,547 | 0.000208 | 277,770 |
| 13 | **FUEL & PURCHASED POWER** | | | | |
| | Summer | | | | |
| | On Peak kWhs | | 153,880,266 | 0.081447 | 12,533,078 |
| | Off Peak kWhs | | 464,852,681 | 0.031947 | 14,850,625 |
| | Shoulder Peak kWhs | | 147,863,362 | 0.045637 | 6,747,990 |
| | Winter | | | | |
| | On Peak kWhs | | 199,664,087 | 0.069950 | 13,966,439 |
| | Off Peak kWhs | | 366,449,150 | 0.020450 | 7,493,767 |
| 14 | TOTAL REVENUE | | | | $125,442,308 |
| 15 | **TOTAL LGS-85N** | kWh | 1,332,709,547 | | |
| 16 | | Cust | 651 | | |

Exhibit ___(SJB-4)
Schedule 3

**TUCSON ELECTRIC POWER**
**LARGE GENERAL SERVICE TIME OF USE - LGS-85N**
Hybrid Methodology

| Line No. | | | New Billing Determinants | Proposed Rate | Proposed Revenue |
|---|---|---|---|---|---|
| 1 | Customer Charge | | 7,812 | $371.88 | $2,905,127 |
| | **DELIVERY DEMAND CHARGES** | | | | |
| | Summer Demand | | | | |
| 2 | On Peak kW | | 1,753,711 | $8.74 | $15,327,437 |
| 3 | Off Peak kW | | 1,753,711 | $1.00 | $1,751,958 |
| | Winter Demand | | | | |
| 4 | On Peak kW | | 1,732,383 | $8.74 | $15,141,030 |
| 5 | Off Peak kW | | 1,732,383 | $1.00 | $1,730,651 |
| | **DELIVERY ENERGY CHARGES** | | | | |
| | Summer | | | | |
| 6 | On Peak kWhs | | 153,880,266 | $0.041559 | $6,395,059 |
| 7 | Off Peak kWhs | | 464,852,681 | $0.020309 | $9,440,539 |
| 8 | Shoulder Peak kWhs | | 147,863,362 | $0.025643 | $3,791,631 |
| | Winter | | | | |
| 9 | On Peak kWhs | | 199,664,087 | $0.036876 | $7,362,905 |
| 10 | Off Peak kWhs | | 366,449,150 | $0.015626 | $5,726,303 |
| 11 | Revenue Delivery Charges | | | | $69,572,639 |
| 12 | Generation Capacity | | 1,332,709,547 | 0.000208 | 277,770 |
| 13 | **FUEL & PURCHASED POWER** | | | | |
| | Summer | | | | |
| | On Peak kWhs | | 153,880,266 | 0.081447 | 12,533,078 |
| | Off Peak kWhs | | 464,852,681 | 0.031947 | 14,850,625 |
| | Shoulder Peak kWhs | | 147,863,362 | 0.045637 | 6,747,990 |
| | Winter | | | | |
| | On Peak kWhs | | 199,664,087 | 0.069950 | 13,966,439 |
| | Off Peak kWhs | | 366,449,150 | 0.020450 | 7,493,767 |
| 14 | TOTAL REVENUE | | | | $125,442,308 |
| 15 | **TOTAL LGS-85N** | kWh | 1,332,709,547 | | |
| 16 | | Cust | 651 | | |

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

**In the Matter of the Filing by Tucson Electric ) Docket No. E-01933A-05-0650**
**Power Company to Amend Decision No. 62103 )**

**In the Matter of the Application of Tucson Electric )**
**Power Company for the Establishment of Just and)**
**Reasonable Rates and Charges Designed to Realize ) Docket No. E-01933A-07-0402**
**A Reasonable Rate of Return on the Fair Value of )**
**Its Operations Throughout the State of Arizona )**

**EXHIBIT__(SJB-5)**

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

## Tucson Electric Power Company
## Revised Calculation of Termination Cost Regulatory Asset Charge ("TCRA")

| | 2009 kWh Sales | kWh Sales Allocation Factor | Rate Base | Rate Base Allocation Factor | TCRA Revenue Requirement kWh | TCRA Revenue Requirement Rate Base | TCRA Revenue Requirement Difference | TCRA Rate Per kWh kWh | TCRA Rate Per kWh Rate Base |
|---|---|---|---|---|---|---|---|---|---|
| Residential | 4,057,909,707 | 41.06% | 507,485,022 | 51.64% | 51,218,174 | 64,423,235 | 13,205,061 | 0.012622 | 0.015876 |
| General Service | 3,536,655,904 | 35.78% | 354,002,346 | 36.02% | 44,639,006 | 44,939,211 | 300,204 | 0.012622 | 0.012707 |
| Large Light & Power | 1,009,916,561 | 10.22% | 50,716,184 | 5.16% | 12,746,977 | 6,438,221 | (6,308,756) | 0.012622 | 0.006375 |
| Mining | 993,510,862 | 10.05% | 34,877,502 | 3.55% | 12,539,907 | 4,427,562 | (8,112,345) | 0.012622 | 0.004456 |
| Lighting | 44,057,808 | 0.45% | 10,840,637 | 1.10% | 556,089 | 1,376,176 | 820,087 | 0.012622 | 0.031236 |
| Public Authority | 241,969,743 | 2.45% | 24,812,468 | 2.52% | 3,054,097 | 3,149,846 | 95,749 | 0.012622 | 0.013018 |
| **Rate Schedules** | | | | | | | | | |
| R01 | 3,832,493,679 | 38.77% | 478,682,748 | 48.71% | 48,373,015 | 60,766,899 | 12,393,884 | 0.012622 | 0.015856 |
| R02 | 5,740,124 | 0.06% | 365,592 | 0.04% | 72,451 | 46,410 | (26,040) | 0.012622 | 0.008085 |
| R21 | 56,407,817 | 0.57% | 7,281,382 | 0.74% | 711,969 | 924,343 | 212,374 | 0.012622 | 0.016387 |
| R70 | 66,526,767 | 0.67% | 9,428,747 | 0.96% | 839,688 | 1,196,942 | 357,254 | 0.012622 | 0.017992 |
| R201 | 96,741,319 | 0.98% | 11,726,553 | 1.19% | 1,221,051 | 1,488,640 | 267,589 | 0.012622 | 0.015388 |
| GS10 | 1,876,733,213 | 18.99% | 209,893,343 | 21.36% | 23,687,774 | 26,645,138 | 2,957,363 | 0.012622 | 0.014198 |
| GS11 | 64,688,259 | 0.65% | 6,908,269 | 0.70% | 816,483 | 876,978 | 60,495 | 0.012622 | 0.013557 |
| GS76 | 140,498,681 | 1.42% | 12,190,899 | 1.24% | 1,773,348 | 1,547,587 | (225,761) | 0.012622 | 0.011015 |
| GS13 | 1,298,675,285 | 13.14% | 114,134,487 | 11.61% | 16,391,635 | 14,488,926 | (1,902,710) | 0.012622 | 0.011157 |
| GS85 | 138,662,019 | 1.40% | 10,217,836 | 1.04% | 1,750,166 | 1,297,114 | (453,052) | 0.012622 | 0.009355 |
| GS31 | 17,398,448 | 0.18% | 657,512 | 0.07% | 219,600 | 83,469 | (136,131) | 0.012622 | 0.004797 |
| I14 | 750,777,615 | 7.60% | 38,452,081 | 3.91% | 9,476,174 | 4,881,341 | (4,594,833) | 0.012622 | 0.006502 |
| I90 | 259,138,946 | 2.62% | 12,264,103 | 1.25% | 3,270,803 | 1,556,880 | (1,713,923) | 0.012622 | 0.006008 |
| Total Mining | 993,510,862 | 10.05% | 34,877,502 | 3.55% | 12,539,907 | 4,427,562 | (8,112,345) | 0.012622 | 0.004456 |
| Total Lighting | 44,057,808 | 0.45% | 10,840,637 | 1.10% | 556,089 | 1,376,176 | 820,087 | 0.012622 | 0.031236 |
| Pub Auth P40 | 108,881,979 | 1.10% | 13,867,159 | 1.41% | 1,374,288 | 1,760,382 | 386,094 | 0.012622 | 0.016168 |
| Pub Auth P43-44 | 133,087,764 | 1.35% | 10,945,309 | 1.11% | 1,679,809 | 1,389,464 | (290,345) | 0.012622 | 0.010440 |
| Total | 9,884,020,585 | 100% | 982,734,159 | 100% | 124,754,251 | 124,754,251 | - | | |

Baron Exhibit__(SJB-5)

EXHIBIT
Kroger-2
ADMITTED

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

**Mike Gleason, Chairman**
**William A. Mundell**
**Jeff Hatch-Miller**
**Kristin K. Mayes**
**Gary Pierce**

| | |
|---|---|
| **In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103** | **) Docket No. E-01933A-05-0650 )** |
| **In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona** | **) ) ) Docket No. E-01933A-07-0402 ) )** |

**SUPPLEMENTAL**

**DIRECT TESTIMONY**

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

**J. KENNEDY AND ASSOCIATES, INC.**
**ROSWELL, GEORGIA**

**June 2008**

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103** | **) Docket No. E-01933A-05-0650** |
| **In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona** | **) Docket No. E-01933A-07-0402** |

**SUPPLEMENTAL DIRECT TESTIMONY OF STEPHEN J. BARON**

**Q. Please state your name and business address.**

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

**Q. Have you previously submitted testimony in the proceeding?**

A. Yes. I submitted Direct Testimony.

**Q. What is the purpose of your Supplemental Direct Testimony?**

A. I will be presenting brief testimony in support of the Proposed Rate Settlement Agreement of May 29, 2008 ("Settlement Agreement"). Kroger Company is a signatory to this agreement and fully supports the settlement for the reasons that I will discuss below. Kroger did not present testimony on the overall level of TEP's revenue requirement increase or on the alternative ratemaking methodology issues. Our testimony was limited to the allocation of the overall approved revenue increase to rate classes ("rate spread") and to specific rate design issues affecting general service rates. Consistent with this prior testimony, my Supplemental Direct testimony will only address these issues within the context of the Settlement Agreement. Notwithstanding this, Kroger supports the entire settlement and believes that it will result in reasonable rates.

**Q. Have you specifically reviewed the provisions of the Settlement Agreement regarding rate spread?**

A. Yes. The Settlement Agreement requires a uniform 6.1% revenue increase to each rate schedule. Based on my review of the Company's filed class cost of service study, I believe that this is a reasonable settlement result.

**Q. Have you reviewed the proposed settlement rate design for general service and large general service rate schedules?**

A. Yes. Based on my review of the proposed tariffs and the issues that I addressed in my Direct Testimony in this case, I believe that the proposed settlement is reasonable and consistent with the underlying cost of service. I therefore fully support and recommend approval of the Settlement Agreement.

**Q. Are there additional reasons why you believe that the Commission should approve the Settlement Agreement?**

A. Yes. The rate case moratorium provision, freezing base rates until December 31, 2012 is likely to be of significant benefit to all of the Company's ratepayers.

**Q. Does that complete your testimony?**

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
Mesquite - 1
ADMITTED

**COMMISSIONERS**

**MIKE GLEASON, Chairman**
**WILLIAM A. MUNDELL**
**JEFF HATCH-MILLER**
**KRISTIN K. MAYES**
**GARY PIERCE**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA. | ) | DOCKET NO. E-01933A-07-0402 |
| IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103. | ) | DOCKET NO. E-01933A-05-0650 |

**TESTIMONY OF LEESA NAYUDU AND GREG BASS ON BEHALF OF MESQUITE POWER, L.L.C., SOUTHWESTERN POWER GROUP II, L.L.C., BOWIE POWER STATION, L.L.C. AND SEMPRA ENERGY SOLUTIONS LLC (COLLECTIVELY "MESQUITE, ET AL.")**

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**PREPARED DIRECT TESTIMONY
OF
LEESA NAYUDU AND GREG BASS**

**Q.1 Please state your names and business affiliations.**

A.1 My name is Leesa Nayudu, and I am Director of Origination with Sempra Generation, which owns Mesquite Power, L.L.C. ("Mesquite"). My name is Greg Bass, and I am Director of Retail Commodity Operations with Sempra Energy Solutions LLC ("SES").

**Q.2 On whose behalf are you providing this testimony?**

A.2 We are testifying on behalf of Mesquite, Southwestern Power Group II, L.L.C., Bowie Power Station, L.L.C. and SES, (collectively "Mesquite et al."). Leesa Nayudu is the sponsoring witness for those portions of the Direct Testimony which pertain to subjects other than retail electric competition and direct access; and Greg Bass is the sponsoring witness as to retail electric competition and direct access matters. Mesquite et al. were granted intervention in this proceeding by means of a Procedural Order issued on September 13, 2007. Thereafter, we filed Prepared Direct Testimony on February 29, 2008; and, we were active participants in the settlement negotiations which resulted in the May 29, 2008 Settlement Agreement that was filed with the Commission that same day.

**Q.3 What is the purpose of your testimony at this time?**

A.3 Each of the companies comprising Mesquite et al. has signed the Settlement Agreement. Pursuant to the Procedural Order issued by the Administrative Law Judge Jane Rodda on May 12, 2008, Mesquite et al. are providing this Direct Testimony in support of the Settlement Agreement as it relates to their collective interests.

**Q.4 Please identify those areas of the Settlement Agreement which you will address in your testimony.**

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A.4 We will be discussing certain portions of Sections I (Rate Increase), II (Ratemaking Treatment of TEP's Generating Assets and Fuel Costs), VII (Purchased Power and Fuel Adjustment Clause), XII (Certificate of Convenience and Necessity) and XIII (Returning Customer Direct Access Charge).

**Q.5 What is the position of Mesquite et al. with regard to the proposed rate increase in base rates for TEP set forth in Section II?**

A.5 As indicated in the Direct Testimony we filed on February 29, 2008, Mesquite et al. believe it is important that TEP be allowed an opportunity to receive revenues sufficient to allow it to be a creditworthy purchaser in the competitive wholesale market in Arizona. We ourselves do not presume to know what level of increase in base rates will allow TEP to retain that status. However, given TEP's stated intent to obtain a significant portion of its future power resource requirements from the competitive wholesale electric power market, and TEP's acceptance of the proposed increase over average base rates of approximately six percent (6%), it is reasonable to assume that TEP has determined that such an increase will enable it to retain the requisite creditworthiness. We therefore support TEP's acceptance of the rate increase contained in the Settlement.

**Q.6 Does Mesquite et al. believe that the inclusion of TEP's generation assets provided for in Section III is appropriate?**

A.6 Yes. Given that TEP has agreed that cost-of-service ratemaking shall be used for purposes of these proceedings, Mesquite et al. believe that all of TEP's generating assets should be included in its rate base at original cost for ratemaking purposes as provided for in Section 3.1.

**Q.7 In that regard, does that mean that you anticipate that TEP will have little occasion to look to the competitive wholesale electric power market in the future, since**

**Section 3.1 includes generation assets acquired by TEP after December 31, 2006, but before December 31, 2012?**

A.7 No, not at all. In fact the last sentence in Section 3.1 expressly states that

> "This provision is not intended to create a presumption in favor of [company-owned] generation, and the Signatories acknowledge that TEP is obligated to consider all reasonable alternatives when evaluating how to meet its service obligations to its customers."

Against that background, as well as the Recommended Best Practices For Procurement adopted by the Commission on December 4, 2007 in Decision No. 70032, Mesquite et al. anticipate that TEP will be an active participant in the competitive wholesale electric power market in Arizona in the future.

**Q.8 Do Mesquite et al. support the proposed Purchased Power and Fuel Adjustment Clause ("PPFAC") which is the subject of Section VII?**

A.8 Yes, for two (2) reasons. First, we believe that the existence of the proposed PPFAC will enable TEP to remain a creditworthy purchaser within the competitive wholesale electric power market in Arizona. However, as stated in our February 29, 2008 Direct Testimony, Mesquite et al.'s support in this regard is conditioned upon TEP being required to demonstrate its ongoing compliance with the Recommended Best Practices For Procurement in connection with purchased power and fuel expense TEP would seek to recover through the PPFAC.

Second, and in relation to the foregoing condition, Mesquite et al. believe that the provisions of the Proposed Plan of Administration ("POA") for the PPFAC, as attached to the Settlement Agreement, provide for that transparency and access to information necessary to insure that TEP can be required to demonstrate, if necessary, its ongoing compliance with the Recommended Best Practices For Procurement. In that regard, at the forthcoming hearing on the proposed Settlement Agreement, Mesquite et al.'s counsel will inquire of the appropriate TEP witness as to whether TEP intends to interpret and administer its "company procurement protocols," as referenced in Section 8 [page 8] of

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the POA, so as to comply with the Recommended Best Practices For Procurement. For purposes of this Direct Testimony in support of the proposed PPFAC, Mesquite et al. assume that the answer to that question will be in the affirmative.

**Q.9 In their February 29, 2008 Direct Testimony, Mesquite et al. opposed TEP's proposed restoration of the exclusivity of its CC&N, in the event that the cost-of-service ratemaking methodology was used to determine TEP's post-January 1, 2009 rates. Are Mesquite et al. satisfied with how Section XII resolves this issue; and, if so, why?**

A.9 Mesquite et al. are satisfied with the resolution approach reflected in Section XII, because it in essence preserves the "status quo" with respect to the status of retail electric competition in Arizona. More specifically, Mesquite et al. believe that retail electric competition in Arizona has not been foreclosed because of the Arizona Court of Appeals decision in the Phelps Dodge case, and that the Commission possesses the jurisdiction and authority to proceed with retail electric competition at this time if it desires to do so. At the same time, we recognize that TEP and others may not share that view. It is our belief that, if the Commission has any question as to its jurisdiction and authority to proceed with retail competition in the aftermath of the Phelps Dodge decision, it could resolve that question within the context of a generic proceeding of general applicability, and that it should not resolve it within the context of a rate case specific to a single utility.

In this regard, several months ago in a proceeding involving an Application by Sempra Energy Solutions LLC ("SES") for an Electric Service Provider CC&N to provide competitive retail electric service in the certificated service areas of TEP, Arizona Public Service Company ("APS") and Salt River Project, counsel for SES presented detailed legal argument as to why the Commission currently has the necessary jurisdiction and authority to act upon SES' CC&N request. The Administrative Law Judge assigned to the SES proceeding [Docket No. E-03964A-06-0168] has yet to issue a ruling as to whether that proceeding can go forward at this time. Thus, the status of

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electric retail competition in Arizona remains open at this time, and Section XII recognizes and preserves that status.

**Q.10 In what manner do the provisions of Section XII preserve the "status quo" of retail competition?**

A.10 First, TEP's proposed restoration of the exclusivity of its CC&N is removed from the scope of issues to be resolved through this proceeding. If the Commission desires to address that question at all, Section 12.1 provides that it would do so in a "generic docket," but it does not presume that the Commission believes there is a need to conduct such a proceeding.

Second, Section 12.2 recognizes TEP's obligation to recognize

> "the existence of any Commission direct access program and the potential for future direct access customers"

as a part of TEP's ongoing planning activities. In so doing, it does not expressly assume anything with regard to the status of any such program. Whereas, under TEP's originally proposed restoration of the exclusivity of its CC&N, the existence of any direct access program and the potential for future direct access customers would automatically have been foreclosed.

Third, Section 12.3 provides that

> "This Agreement is not intended to create, confirm, diminish or expand an exclusive right for TEP to provide electric service within its certificated area where others may legally also provide such service…"

Simply stated, the Settlement Agreement does not disturb the legal status of retail electric competition in Arizona, whatever that status may be.

Thus, for these reasons, Mesquite et al. believe that Section XII represents an appropriate resolution.

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**Q.11 Is Section XIII relevant to what you have been discussing with respect to Section XII; and, if so, in what manner?**

A.11 Section XIII provides that TEP will file a Returning Customer Direct Access Charge ("RCDAC") tariff within ninety (90) days of the effective date of the Commission's order approving the Settlement Agreement. The mere existence of such a tariff presupposes the possibility of direct access customers, and the possible existence of retail electric competition concurrent with the use of a cost-of-service methodology for ratemaking for the incumbent electric utility. This approach is consistent with the preservation of the "status quo" approach reflected in Section XII, which has been previously discussed. In addition, it is conceptually consistent in this regard with the tariff system utilized by APS.

**Q.12 Is the subject and status of retail electric competition a matter of interest only for SES, as opposed to the entirety of Mesquite et al.?**

A.12 Not at all. By definition, a direct access customer is one who will be receiving its power supply from someone other than the incumbent electric utility, which in this instance would be TEP. Thus, the direct access market occasioned by the existence of retail electric competition is of interest to independent power producers or merchant generators, just as is the market represented by incumbent electric utilities, such as TEP.

**Q.13 Does that complete Mesquite et al.'s Direct Testimony in support of the proposed Settlement Agreement?**

A.13 Yes, it does.

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

EXHIBIT
Mesquite - 2
ADMITTED

**COMMISSIONERS**

**MIKE GLEASON, Chairman**
**WILLIAM A. MUNDELL**
**JEFF HATCH-MILLER**
**KRISTIN K. MAYES**
**GARY PIERCE**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA. | DOCKET NO. E-01933A-07-0402 |
| IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103. | DOCKET NO. E-01933A-05-0650 |

**REBUTTAL TESTIMONY OF GREG BASS ON BEHALF OF**

**MESQUITE POWER, L.L.C., SOUTHWESTERN POWER GROUP II, L.L.C.,**

**BOWIE POWER STATION, L.L.C. AND SEMPRA ENERGY SOLUTIONS LLC**

**(COLLECTIVELY "MESQUITE, ET AL.")**

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**REBUTTAL TESTIMONY
OF
GREG BASS**

**Q.1 Are you the same Greg Bass whose prepared Direct Testimony (along with that of Leesa Nayudu) was filed upon behalf of Mesquite et al. on June 11, 2008 in Docket Nos. E-01933A-07-0402 and E-01933A-05-0650?**

A.1 Yes, I am.

**Q.2 What is the purpose of this prepared Rebuttal Testimony on behalf of Mesquite et al.?**

A.2 By means of this prepared Rebuttal Testimony, Mesquite et al. desire to rebut the suggestion set forth by Residential Utility Consumer Office ("RUCO") witness William A. Rigsby in his July 2, 2008 prepared Direct Testimony that the Commission should address in these proceedings the status of retail electric competition in Tucson Electric Power Company's ("TEP") service area. In that regard, and in the interest of brevity, by way of background and as a part of this prepared Rebuttal Testimony, Mesquite et al. incorporate by reference the discussion set forth at page 5, line 5 through page 7, line 10 of their June 11, 2008 prepared Direct Testimony in these proceedings. In addition, I will briefly comment upon a portion of the prepared Direct Testimony of IBEW Local No. 1116 witness Frank Grijalva.

**Q.3 In their prepared Direct Testimony, Mesquite et al. discuss why they believe that the approach reflected in Sections XII and XIII of the Settlement Agreement represents the appropriate manner for addressing the subject of retail electric competition for purposes of these proceedings. Why do Mesquite et al. believe that RUCO's suggestion is inappropriate?**

A.3 Because RUCO, in effect, is attempting to reverse the Commission's previous promulgation of regulations providing for retail electric competition in Arizona through the procedural means of a rate case involving a single electric public service corporation. As Section XII of the Settlement Agreement observes, a generic docket is the appropriate procedural means by which the Commission may revisit the status of retail electric competition in the service territory of TEP and all other Affected Utilities, "should the Commission choose to do so."

RUCO witness Rigsby's prepared Direct Testimony unequivocally states that RUCO is opposed to the prospect of retail electric competition for residential ratepayers under any circumstances. However, the procedural means and timing that RUCO has suggested for achieving its stated goal are inappropriate. The issues RUCO presumably seeks to address, and the arguments it may wish to make, are not peculiar to TEP and its residential ratepayers. Rather, they are industry-wide in nature, and, if they are to be addressed at some future date, it should be within the context of a general proceeding instituted for that purpose.

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**Q.4 In his prepared Direct Testimony in support of the May 29, 2008 Settlement Agreement, IBEW Local No. 1116 witness Frank Grijalva states that the union would have preferred that**

> **"...the important matters addressed in Paragraph 12.1 had been tackled in the instant proceeding instead of some yet-to-be filed generic docket." [page 4, lines 1-4]**

**Do you wish to comment upon that statement at this time?**

A.4 Only to the extent of noting that, while that may have been the preferred negotiating posture of the union at one point in time, its official and final negotiating posture is that Mr. Grijalva is offering testimony at this time

> "...to express the Union's <u>unqualified support</u> for the proposed Settlement Agreement." [page 1, lines 10-14] [emphasis added]; and,

he further states that

> "…IBEW Local 1116 fully and strongly supports the Commission's adoption of the proposed Settlement Agreement in toto."[page 4, lines 11-13] [emphasis added]

which includes Sections XII and XIII of the May 29, 2008 Settlement Agreement.

**Q.5 Doest that complete the prepared Rebuttal Testimony of Mesquite et al.?**

A.5 Yes, it does.

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EXHIBIT
Mesquite-3
ADMITTED

# PREPARED DIRECT TESTIMONY
# OF
# LEESA NAYUDU

RECEIVED

FEB 29 2008

ARIZONA CORP. COMM
400 W CONGRESS STE 218 TUCSON AZ 85701

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AZ CORP COMMISSION
DOCKET CONTROL

MESQUITE POWER LLC. et al.
DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650
February 29, 2008.

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**Prepared Direct Testimony**
**Of**
**Leesa Nayudu**

**Q.1 Please state your name and business affiliation.**

A.1 My name is Leesa Nayudu, and I am Regional Director Of Operations (West) for Sempra Generation.

**Q.2 On whose behalf are you providing this testimony?**

A.2 I am testifying on behalf of Mesquite Power, L.L.C., Southwestern Power Group II, L.L.C., Bowie Power Station, L.L.C. and Sempra Energy Solutions LLC, (collectively "Mesquite et al."). Mesquite et al. were granted intervention in this proceeding by means of a Procedural Order issued on September 13, 2007.

**Q.3 What is the purpose of your testimony?**

A.3 Mesquite et al. have certain issues they wish to address at this time, either (i) for the purpose of indicating what their position is with regard to the same, or (ii) for the purpose of indicating that they desire more information and/or a better understanding as to what TEP is proposing. With respect to the latter, hopefully TEP will provide that information and/or understanding in testimony it will be filing at a later stage in this proceeding.

**Q.4 Do Mesquite et al. have a position on TEP's contention that, pursuant to the provisions of the 1999 Settlement Agreement, TEP is entitled to charge market-based rates after January 1, 2009?**

A.4 No, we do not. Representatives of Mesquite et al. were not involved in the negotiations which resulted in TEP's 1999 Settlement Agreement, nor did they participate in the hearings before the Commission which resulted in Decision No. 62103. Hence, it would be presumptuous of Mesquite et al. to opine as to what the signatory parties to the 1999 Settlement Agreement and/or the Commission may have intended with respect to how TEP's rates were to be established for service provided by TEP on and after January 1, 2009.

**Q.5 With reference to the "regulatory asset(s)" proposed by TEP in connection with its "Cost-of-Service Methodology" and its "Hybrid Methodology," do Mesquite et al. have a position?**

A.5 Not as of this stage in this proceeding. Depending on the evidentiary record yet to be developed through the hearing process, our current lack of a position on this issue might change, and then again it might not.

**Q.6 Do Mesquite et al. have a position on the Purchase Power and Fuel Adjustment Clause ("PPFAC") which TEP has proposed in connection with its "Cost-of-Service Methodology" and its "Hybrid Methodology"?**

A.6 Yes. From a conceptual perspective, Mesquite et al. support a PPFAC for TEP, provided that, in connection with purchased power and fuel expense(s) to be recovered thereunder, TEP would be required to demonstrate its ongoing compliance with the Recommended Best Practices For Procurement adopted by the Commission on December 4, 2007 in Decision No. 70032. We do not believe that TEP should be allowed rate recovery for purchased power and fuel expense(s) where it cannot demonstrate compliance with the Commission's Recommended Best Practices For Procurement.

**Q.7 Assuming such compliance by TEP, why do Mesquite et al. believe that a PPFAC would be appropriate for TEP?**

A.7 As TEP witness David Hutchens has noted in his July 2, 2007 Direct Testimony

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> "TEP relies on significant quantities of natural gas and purchased power to meet its retail load. Although TEP has served the majority of its load with company-owned generating resources, it relies on natural gas and purchased power to meet a growing percentage of its customer demand. This gas and power is purchased at market prices, so TEP should be allowed to recover these costs. The PPFAC is designed to recover or return the difference between the actual cost of natural gas and the purchased power versus the cost of natural gas and purchased power established in base rates.
>
> "TEP is concerned about the volatile fuel and energy markets causing large deferrals of uncollected costs. Without an adjustor mechanism to timely address these costs in a way that sends accurate price signals to customers, the Company could incur substantial deferrals that could affect its ability to secure financing on favorable terms. It also could affect the Company's ability to secure natural gas and purchase power in the future on terms as favorable to the Company and its customers. In fact, the Company could face credit terms that could hurt its ability to secure reasonably priced fuel and purchase power in the future by requiring credit enhancements such as repayment or letters of credit. This could lead to the inability to hedge future prices or enter into long term resource or contract commitments and being forced to rely heavily on the volatile short-term and spot markets." [Hutchens Direct Testimony, page 30, line 18 – page 31, line 11] [emphasis added]

As sellers in the competitive wholesale electric power market in Arizona, Mesquite et al. can attest to the importance of TEP being considered a creditworthy purchaser, and the problems Mr. Hutchens has indicated TEP might encounter without some form of Commission – approved adjustor mechanism, such as a PPFAC.

In addition, as TEP witness Judah Rose notes at pages 36-37 of his July 2, 2007 Direct Testimony, the competitive wholesale electric power market in Arizona has become quite robust and large in relation to TEP's power resource needs. Thus, it would be unfortunate for TEP and its ratepayers if the absence of an adjustor mechanism precluded it from obtaining power on favorable terms and conditions that the competitive market might otherwise offer.

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**Q.8 Do Mesquite et al. have a position with respect to TEP's proposed restoration of the exclusivity of its CC&N under both its "Cost-of-Service Methodology" and its "Hybrid Methodology"?**

A.8 Yes, we are opposed to TEP's proposed restoration in each instance. In that regard, the reasoning of TEP witness James S. Pignatelli in support of TEP's restoration proposal is worth noting, because of the flawed "linkage" it assumes between cost-of-service ratemaking and the assumed absence of the prospect of retail electric competition:

> "...<u>if the Commission adopts the Cost-of-Service Methodology, then it will have abandoned retail electric competition for TEP's customers.</u> In that case, TEP should have the right to exclusively provide electric service within its certificate area. To ensure that TEP has the exclusive right to provide electric service, the Commission should order that its exclusive CC&N is restored. Additionally, under the Hybrid Methodology, where a majority of TEP's generation would be returned to cost-of-service ratemaking, it is also appropriate to partially restore the exclusivity of TEP's CC&N." [Pignatelli Direct, page 22, lines 18 – 25] [emphasis added]

There is no direct linkage of this nature in Arizona as this time. Cost-of-service regulation and the Commission's Electric Competition Rules exist quite separate from one another; and, unless and until the Commission rescinds the Electric Competition Rules, it cannot be said that the Commission has "abandoned retail electric competition." In that regard, the flaw in TEP's reasoning exists in both its proposed complete restoration of exclusivity under the "Cost-of-Service Methodology" and its proposed partial restoration of exclusivity under the "Hybrid Methodology." Moreover, in the last two (2) Arizona Public Service Company ("APS") rate cases, the Commission has approved both bundled and unbundled rates for APS, and left its service open to retail electric competition; and, TEP has proposed unbundled rates for each of its three (3) ratemaking methodologies in this proceeding.

**Q.9 What is the position of Mesquite et al. with regard to TEP's proposal to exclude its ownership interest in the Four Corners and Navajo generating stations from TEP's**

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**rate base, and classify those power resources as "Competitive Assets," which could either compete in the competitive wholesale market or sell power to TEP at market-based rates?**

A.9 Before taking a position on this aspect of TEP's "Hybrid Methodology," Mesquite et al. need a better understanding as to (i) how these "Competitive Assets" would be interfaced with and participate in the competitive wholesale market, and (ii) under what circumstances TEP would be allowed to choose to buy power from its "Competitive Assets" at market-based rates. In that regard, Mesquite et al. need to know how and to what extent the Recommended Best Practices For Procurement will apply to and affect this aspect of the "Hybrid Methodology." Stated differently, we need to know how the existence of the "Competitive Assets" would affect when and the extent to which TEP would look to the competitive wholesale market, as contrasted with the situation under its "Cost-Of-Service-Methodology" where TEP would have no "Competitive Assets." Perhaps TEP will provide information on this subject in its forthcoming Rebuttal Testimony.

**Q.10 Are there any other aspects of the "Hybrid Methodology" with regard to which Mesquite et al. would like more information and clarification from TEP?**

A.10 Yes. Despite having reviewed the Direct Testimony of Messrs. Pignatelli and Hutchens, where they discuss the nature of and reasoning underlying the "Hybrid Methodology," it is not clear why TEP has proposed this alternative approach to ratemaking, given their testimony elsewhere as to TEP's need to substantially augment company-owned generation in the future. On the face of it, one would think TEP would want to retain within its rate base power generation resources that still have a useful operating life. Accordingly, before adopting a position on the "Hybrid Methodology," Mesquite et al. would like more information on this aspect of the proposal as well. Perhaps TEP can include such information and clarification in its forthcoming Rebuttal Testimony.

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**Q.11 Are there any other aspects of TEP's July 2, 2007 Application on which Mesquite et al. would like more information and clarification?**

A.11 Yes. It is as yet unclear to us why TEP appears to be proposing to recover most, if not all, of its costs of operating the Luna generating facility through the PPFAC, yet, if we understand the situation correctly, it would include the Luna generating facility in its rate base under both the "Cost-of-Service Methodology" and the "Hybrid Methodology." Under those two (2) scenarios, one would anticipate adjusted test period operating costs associated with Luna would be included in TEP's proposed base rates. Accordingly, any further information or clarification TEP could provide on this subject in its forthcoming Rebuttal Testimony would also be appreciated. Once we have that information, Mesquite et al. can then determine if they have a position on this proposal.

**Q.12 Are there any other aspects of TEP's Application that you would like to comment upon?**

A.12 Not at this time. After we have reviewed TEP's Rebuttal Testimony, Mesquite et al. may have occasion to file additional testimony in accordance with the Procedural Schedule which has been established by Administrative Law Judge Rodda. In addition, we may explore some of these matters in greater detail through cross-examination during the hearing to be held on TEP's Application, as well as other issues which may arise.

**Q.13 Does that complete your Direct Testimony?**

A.13 Yes, it does.

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

Arizona Corporation Commission
DOCKETED
DEC - 4 2007
DOCKETED BY ne

EXHIBIT
Mesquito-5
ADMITTED

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| IN THE MATTER OF COMPETITIVE PROCUREMENT ISSUES IN THE GENERIC INVESTIGATION INTO ELECTRIC RESOURCE PLANNING | DOCKET NO.E-00000E-05-0431<br>DECISION NO. 70032<br>ORDER |

Open Meeting
November 27 and 28, 2007
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

**Introduction**

1. Commission Decision No. 67744 directed Staff to schedule workshops on resource planning issues. Additionally, as part of the Settlement Agreement of that case, it was agreed that "the Commission Staff will schedule workshops on resource planning issues to focus on developing needed infrastructure and developing a flexible, timely, and fair competitive procurement process." (Paragraph 79, Settlement Agreement).

2. On April 5, 2007, Staff docketed a Request for Meetings Notice, and indicated that a series of three workshops specifically related to issues of competitive procurement would be held, and that the remaining issues related to resource planning would be conducted in other workshops and noticed separately. Three workshops on competitive procurement were held on April 25, 2007; May 23, 2007; and July 13, 2007. Eight entities filed nine sets of written comments.

3. On October 2, 2007, Staff issued a Draft Staff Report on Competitive Procurement Issues, with a request for comments to be filed by October 12, 2007. Six entities filed comments in response to the Draft Staff Report. Along with its memo, Staff filed its Final Staff Report on Competitive Procurement Issues.

**Discussion**

4. It is Staff's intention to continue to facilitate competitive wholesale market options for the acquisition of resources to serve electric consumers. Staff believes that conducting a rulemaking on procurement issues is premature at this time. To enable the procurement process to go forward expeditiously, Staff has recommended that the Commission adopt Recommended Best Practices for Procurement. The Recommended Best Practices include types of acceptable methods of procurement, a preference for requests for proposals ("RFPs"), and the role of an independent monitor. Staff believes that these Recommended Best Practices would provide a means by which the Commission, ratepayers, and bidders in the wholesale market can be assured that the procedures for obtaining new resources are fair, transparent, and result in the most economical resources being selected.

**Staff Recommendation**

5. Staff has recommended that the Commission adopt the following Recommended Best Practices for Procurement.

## RECOMMENDED BEST PRACTICES FOR PROCUREMENT

### Procurement Methods

1. The following procurement methods are considered to be acceptable for the wholesale acquisition of energy, capacity, and physical power hedge transactions:

   A. Purchases through third party, on-line trading systems, including but not limited to the Intercontinental Exchange, Bloomberg, California Independent System Operator, New York Mercantile Exchange, or other similar on-line third party systems.

   B. Purchases from qualified, third party, independent energy brokers.

   C. Purchases from non-affiliated entities through auctions or a request for proposals ("RFP") process.

. . .

D. Bilateral contracts with non-affiliated entities.

E. Bilateral contracts with affiliated entities, provided that non-affiliated entities are provided notice of and an opportunity to beat any proposed contract before executing the transaction.

F. Any other competitive procurement process approved by the Commission.

2. Utilities should seek to use an RFP as the primary acquisition process. Exceptions may include the following:

A. For emergencies. An emergency is an unknown and unforeseeable condition (i) not arising from acts or omissions by the utility which are not in accord with good utility practice, (ii) that is temporary in nature, (iii) that threatens reliability or poses some other significant risk to the system, and (iv) where the subject procurement is not greater in quantity or duration than what is necessary for the utility to restore the system to a safe and reliable condition.

B. For short-term acquisitions to maintain system reliability.

C For other components of energy procurement, such as transmission projects, fuels, and fuel transportation.

D. When the planning horizon is two years or less.

E. When a utility encounters a genuine, unanticipated opportunity to acquire a power supply resource at a clear and significant discount when compared with the cost of acquiring new generating facilities that will provide unique value to customers.

F. For transactions that satisfy obligations under the Renewable Energy Standard rules and for demand-side management/demand response programs.

**Independent Monitor**

1. An independent monitor should be used in all RFP processes for procurement of new resources.

2. The utility should consult with Commission Staff and jointly select three to five companies or consultants ("vendor list") who can serve as an independent monitor.

3. The utility will file its vendor list in this docket for interested parties' review. Parties will have 30 days to object to a vendor's inclusion on the list.

4. Within 60 days of the filing of the vendor list, Staff will endorse the vendors it determines are appropriate. Once the vendors are endorsed by Staff, the utility would be able to retain any of the authorized vendors for future RFPs. The utility is required to provide written notice to Staff of its retention of the independent monitor.

5. The utility should enter into a contract with the monitor and should pay the monitor. Reasonable bidders' fees may be used to help offset these costs. When appropriate, the utility may request recovery of its payments to the monitor in customer rates.

6. One week prior to the deadline for submitting bids, the utility should provide the independent monitor with a copy of any bid proposal prepared by the utility or its affiliate, or any benchmark or reference cost the utility has developed against which to evaluate the bids. The independent monitor should take steps to secure the utility bid or benchmark price in a location not known or accessible to any of the bidders or the utility or its affiliate.

7. The independent monitor should provide reports (at least monthly) to Commission Staff throughout the RFP process.

## CONCLUSIONS OF LAW

1. The Commission has jurisdiction the subject matter of the application.

2. The Commission, having reviewed the application and Staff's Memorandum dated November 6, 2007, concludes that it is in the public interest to adopt the Recommended Best Practices for Procurement.

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ORDER

IT IS THEREFORE ORDERED that the Recommended Best Practices for Procurement is adopted.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

**BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION**

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I DEAN S. MILLER, Interim Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 4th day of December, 2007.

DEAN S. MILLER
Interim Executive Director

DISSENT: ______________________

DISSENT: ______________________

EGJ:BEK:lhm\KT

SERVICE LIST FOR: Generic Investigation
DOCKET NO. E-00000E-05-0431

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EXHIBIT
RUCO 1
admitted

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 29, 2008

# TABLE OF CONTENTS

## INTRODUCTION

Q. Please state your name, position, employer and address.

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding the "Cost of Service" proposal in Tucson Electric Power Company's ("Company" or "TEP") application for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of its operations throughout the state of Arizona. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended December 31, 2006.

**BACKGROUND**

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base and the Company's overall revenue requirement. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of eleven sets of data requests, the review and analysis of Company responses to Arizona Corporation Commission ("Commission" or "ACC") Staff data requests, conversations with Company personnel and the review of prior ACC dockets related to TEP.

In Decision No. 62103, dated November 30, 1999, the Commission approved a Settlement Agreement, which approved rate reductions for residential and business customers; set the amount, method and recovery period of stranded costs that TEP can collect in customer charges; and established unbundled rates.

Q. What areas will you address in your testimony?

A. I will address issues related to rate base, operating income and revenue requirements.

RUCO's witness Mr. William Rigsby will provide an analysis of the cost of capital.

RUCO's witness Ms. Marylee Diaz Cortez will address issues related to rate base, operating income and revenue requirements.

RUCO consultant Mr. Glen Gregory will address issues related to the cost of service study and rate design.

RUCO consultant Mr. Ben Johnson will also address additional issues related with the two alternate ratemaking methodologies, the "Market Methodology" and the "Hybrid Methodology".

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules numbered RLM-1 through RLM-18.

## SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base and operating income issues addressed in your testimony.

A. My testimony addresses the following issues:

**Rate Base**

<u>Accumulated Depreciation</u> - This adjustment is the difference in the computation of the accumulated depreciation produced by the implementation of different depreciation rates between the Company and RUCO.

<u>Springerville Unit 1</u> – RUCO witness Ms. Diaz Cortez addresses this adjustment.

<u>Luna Plant</u> – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Implementation Cost Regulatory Asset – RUCO witness Ms. Diaz Cortez addresses this adjustment.

FAS 143 Accumulated Depreciation Write-Off - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Allowance For Working Capital – This adjustment is the difference in the level of expense recommendations calculated by the Company and RUCO.

**Operating Income**

Springerville Unit 1 Costs - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Annualized Depreciation and Amortization Expenses– This adjustment reflects the level of test-year depreciation expense based on RUCO's adjusted gross plant in service and the Company–proposed depreciation rates.

Disallowance Of Inappropriate/Unnecessary Expenses – RUCO's adjustment to operating expenses removes inappropriate expenditures not necessary in the provisioning of electric service.

Supplemental Executive Retirement Plan – RUCO's adjustment reflects disallowing the costs for the supplemental executive retirement plan.

Incentive Compensation – This adjustment splits the incentive compensation expenses on a 50/50 basis to conform to the recent Commission Decision in the UNS Gas rate case.

Rate-Case Expense – This adjustment is based on RUCO's determination of the fair and reasonable cost to TEP ratepayers for this application process.

Property Tax – This adjustment reflects the appropriate level of property tax expense given RUCO's recommended level of net plant in service.

Normalization Of Overhead Line Maintenance Expense – RUCO's adjustment normalizes the test-year level of overhead line maintenance expense.

Penalty and Fine Expenses – RUCO's adjustment to operating expenses removes expenditures not prudent in the provisioning of electric service.

Luna Plant Costs - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Implementation Costs Regulatory Assets - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Payroll – This adjustment maintains RUCO's strict adherence to the historical test-year principle and disagrees with the Company's proposed proforma adjustment, which averages the payroll expenses for two years.

Payroll Tax – This is a companion adjustment to the payroll expense and is adjusted for same reasons as stated above.

Renewable Resources – This is a conforming adjustment corresponding to the Company's acknowledgment of an omission of $19,274 in expenses to the original filing.

Bad Debt Expense – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Navajo Coal Contract - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Customer Care and Billing – This adjustment removes the cost increase associated with the implementation of a new customer information system.

Gain On Sale of SO2 Allowances - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Employee Recognition – RUCO's adjustment removes costs recorded in the test year associated with employee recognition expenses.

Employee Benefits – RUCO's adjustment removes costs recorded in the test year associated with some employee benefit expenses.

Lime Usage Costs - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Short-Term Sales - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Generating Facilities – Operating Lease - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Miscellaneous Revenues - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Wholesale Trading Activity - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Rate-Case Expenses Associated With Docket No. E-01933A-05-0650 - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Income Tax – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

**REVENUE REQUIREMENTS**

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, based on the "Cost of Service" model RUCO is recommending that the increase in the Company's revenue requirement not exceed:

| TEP | RUCO | DIFFERENCE |
|---|---|---|
| $158,186,000 | $36,254,000 | ($121,932,000) |

My recommended revenue requirement percentage increase versus the Company's proposal is as follows:

| TEP | RUCO | DIFFERENCE |
|---|---|---|
| 22.19 % | 4.04 % | -18.15 % |

RUCO's recommended increase in Fair Value Rate Base ("FVRB") based on the equal weighting of a 50/50 split between Original Cost Rate Base ("OCRB") and Reconstruction Cost New Depreciated Rate Base ("RCND") is summarized on Schedule RLM-1:

| TEP | RUCO | DIFFERENCE |
|---|---|---|
| $1,416,014,000 | $1,359,709,000 | ($56,305,000) |

The detail supporting RUCO's recommended rate base is presented on Schedules RLM-2, RLM-3, RLM-4, RLM-5 and RLM-6.

RUCO's recommended required operating income is shown on Schedule RLM-1 as:

| TEP | RUCO | DIFFERENCE |
|---|---|---|
| $82,069,000 | $72,667,000 | ($9,402,000) |

Schedule RLM-1 presents the calculation of RUCO's recommended revenue requirement.

## RATE BASE

Determination Of Fair Value Rate Base

Q. Please explain the basis for your determination of the FVRB as shown on Schedule RLM-1.

A. RUCO's determination of the FVRB consists of three elements. First, the value of the OCRB was restated to reflect RUCO's adjustments to the various rate base determinants. Second, the value of the RCND was computed. As shown on supporting Schedule RLM-2, RUCO computed RCND by multiplying RUCO's OCRB by the ratio of the Company's OCRB to its RCND as filed. Third, the FVRB was computed on an equally weighted basis (50/50 split) between RUCO's OCRB and RCND.

Q. Please elaborate on the first element of RUCO's FVRB determination.

A. The first element consists of several adjustments to the OCRB. The aggregate adjustment was corroborated between myself and RUCO witness Ms. Diaz Cortez. As shown on Schedule RLM-4, I was responsible in part for Adjustment No. 1 and for Adjustment No. 6. Ms. Diaz Cortez analyzed the remaining rate base adjustments.

<u>RUCO Rate Base Adjustment No. 1 – Accumulated Depreciation</u>

Q. Please explain RUCO's adjustment to the accumulated depreciation balance.

A. The full explanation of this adjustment is a coordinated effort between myself and RUCO witness Ms. Diaz Cortez. I will provide clarification of the various computations involved in this adjustment. Ms. Diaz Cortez will illuminate the background, rationale and ratemaking principles involved in this adjustment.

Q. Please continue with the explanation of your portion of this adjustment.

A. During the initial stage of Discovery, I identified a significant irreconcilable difference in the test-year accumulated depreciation balance between the Company's filing and RUCO's computation. Through extensive discussions with the Company the reason for the discrepancy was identified.

The difference was mainly due to the Company's decision to utilize depreciation rates that differed from those previously authorized for its production/generation plant. My adjustment quantifies the amount of accumulated depreciation the Company failed to record as a result of these inappropriate depreciation rates.

Q. Please explain the methodology of your computation to quantify the Company's inappropriate shortfall.

A. My adjustment concentrates only on the plant associated with electrical production/generation (FERC Accounts 310 through 346); since this is the plant related to the significant irreconcilable difference in the test-year accumulated depreciation balance. First I calculated the accumulated depreciation using the authorized depreciation rates, and then I calculated the accumulated depreciation using the lower depreciation rates the Company had utilized. The difference between the two calculations was then reduced by an adjustment factor.

Q. Please explain this adjustment factor.

A. Through the extensive discovery period on the issue of accumulated depreciation the Company criticized RUCO's methodology to adjust for the Company's use of non-approved depreciation rates and identified several key components in the computation of accumulated depreciation being overlooked by RUCO. Some of these components of concern for the Company included:

1. The Company contends computing depreciation provisions is a highly complicated and time-consuming process;
2. Computing depreciation using an annual-averaging convention versus a monthly convention does not reflect actual account balance; and
3. Computing depreciation based on composite plant account rates versus individual asset unique rates also distorts actual account balance.

Therefore, to reduce the issues in this adjustment, I acknowledged these concerns and refined my adjustment. To recognize the Company's concerns, I calculated the percent difference between the Company's requested level of accumulated depreciation in this filing and the level of accumulated depreciation derived from RUCO's computation based on the Company's "OCRB Adjusted Gross Plant In Service" minus the plant associated with production/generation, which forms the bases for this adjustment. This percentage (-0.74%) represents an adjustment factor, which accurately reconciles the difference between the Company's computation and RUCO's methodology.

Q. Please continue with the explanation of your adjustment to the accumulated depreciation.

A. By removing the portion of my accumulated depreciation adjustment associated with the two different methodologies used between RUCO and the Company, I am able to provide a quantified level of accumulated depreciation directly attributable to the unauthorized depreciation rates implemented by the Company. This quantified level of accumulated depreciation is $49,503,835.

Q. Is there any other element to this adjustment required to conform to all ratemaking principles?

A. Yes, to recognize all the ramifications of this adjustment to increase the accumulated depreciation balance, an additional adjustment must be made to the accumulated deferred income tax ("ADIT") account. Therefore, I increased the ADIT account in an amount equal to the product of multiplying the effective federal and state income tax rate by the adjustment to increase the accumulated depreciation balance. The increase to the ADIT is 39.5% X $49,503,835 = $19,554,498.

Q. Please summarize your adjustment to the test-year accumulated depreciation balance.

A. As mentioned at the beginning of this adjustment, I was responsible for calculation and quantification of this adjustment and the Direct Testimony of RUCO witness Ms. Diaz Cortez supports the principles and theory for this adjustment.

As shown on Schedule RLM-4, column (B) and supported in my Work papers designated as "Dep Rate Study", my total adjustment decreases adjusted test-year rate base by (-$49,503,835) + $19,554,498 = $29,949,337.

<u>RUCO Rate Base Adjustment No. 6 – Allowance For Working Capital</u>

Q. Have you reviewed the Company's working capital calculations?

A. Yes. The Company's working capital request is comprised of a thirteen-month average balance for its prepayment and material and supplies accounts, and its cash working capital request is based on a lead/lag study.

Q. Do you agree with the Company's methodology?

A. Yes. Further, I have reviewed the Company's individual lag day calculations and find them to be reasonable. The only difference between the Company's calculation and RUCO's is the different level of expense recommendations. These adjustments result in a net increase in cash working capital of $3,946,134.

## OPERATING INCOME

Operating Income Summary

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. The Company proposed forty-three adjustments to its historical test-year operating income. RUCO analyzed the Company's adjustments and made several additional adjustments to the operating income as filed by the Company. The testimony of RUCO witness Ms. Diaz Cortez discusses a portion of these adjustments, RUCO consultants address some of these adjustments and I was responsible for reviewing the remainder of the adjustments the Company proposes to its test-year operating income. Finally, as a result of its discovery, RUCO recommends other adjustments. My review, analysis and adjustments are explained below.

Operating Income Adjustment No. 2 – Depreciation Expenses

Q. Please explain your adjustment to increase depreciation expenses.

A. The adjustment is primarily attributable to RUCO's rate base adjustments. RUCO agrees with the set of depreciation rates that TEP is proposing to implement on a going forward basis. However, since RUCO does not have the plant data in as fine a detail as the Company provided in its depreciation study, I computed a composite depreciation rate. These depreciation rates reflect FERC account balances the Company provided in its response to RUCO Data Request 2.13. The actual depreciation rates shown on Schedule RLM-9 were calculated by dividing each FERC account's "test-year depreciation" balance by the "end-of-test-year plant in service" balance. I then computed test-year depreciation by multiplying RUCO's level of test-year gross plant in service by the composite depreciation rates.

As shown on Schedule RLM-8, column (C) and supporting Schedule RLM-9, my adjustment increases adjusted test-year expenses by $4,067,209.

<u>Operating Income Adjustment No. 3 – Disallowance of Inappropriate and/or Unnecessary Expenses</u>

Q. Please explain your analysis of the various operating expense accounts that result in your removal of inappropriate or unnecessary costs for the provisioning of electric service.

A After review of all the journal entries in various FERC accounts and the Company's response to RUCO Data Request 5.17, I determined there were numerous expenditures that were questionable, inappropriate, extravagant and/or unnecessary.

Therefore, as shown on Schedule RLM-10 and supporting workpapers designated as Revised Exhibit A (not attached to this testimony, but provided to the Company simultaneously with this testimony), I have made an adjustment to remove test-year expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of electric service. The back-up documentation denoting each individual expense removed is recorded in Revised Exhibit A: FERC Account Code 921, pages 1 to 28, FERC Account 923, page 1, FERC Account 930.1, page 1, and FERC Account 930.2, pages 1 to 6.

RUCO provided TEP with a copy of the original Exhibit A in a data request to the Company. The Company responded with comments as to the appropriateness and necessity of each expense. After analyzing the Company's response, RUCO removed $1,396,419 from the $1,910,151 test-year expenses submitted on the original Exhibit A.

However, of the 1,449 questionable invoices originally submitted by RUCO on Exhibit A there still remain expenditures that seem questionable, inappropriate, extravagant and/or unnecessary that the Company deem as "valid charges".

Such "valid charges" include:

1. Invoices for the UNS 2006 Board Retreat held September 12 – 16. The Board retreat is held annually in order to strategically plan, discuss and organize the companies current and future; therefore, the directors and spouses were secluded high in the Wasatch Mountains, somewhere around Park City, Utah. The allocated cost to the TEP ratepayers was: 1) $35,816 for lodging at the Stein Eriksen Lodge; 2) $7,489.87 for food services; 3) $6,408.94 for planning and coordination; 4) $5,170.00 for dinners for the directors and their spouses; 5) $2,000.00 for transportation to and from the retreat; 6) $1,168.40 for floral arrangements; and 7) $6,566.38 for embroidered jackets. This UNS 2006 Board Retreat would burden the ratepayers with a total of $64,620.04.
2. Invoices for $130,369.11 recorded by the Company as "Meals and Entertainment – Discretionary".
3. Invoices for $125,000 to the Tucson Regional Economic Opportunities, Inc. to support the creation of new businesses.
4. Invoices for purchases at: Albertson's, Basha's, Food City, Fry's, Safeway's, Walgreen's and Wal Mart totaled $10,987.94.
5. Invoices at Lowns Costumes for $1,757.30 and Party America for $518.34, totaling $2,275.64.
6. Invoices for flowers, gifts, trophies, hams, steaks, toys and clothing totaling $14,942.27.

7. Invoices for various chamber of commerce, community organizations and public relations organizations totaling $28,094.89.

As shown on Schedule RLM-8, column (D) and supporting Schedule RLM-10, this adjustment decreased test-year expenses by $531,731.

Operating Income Adjustment No. 4 – Supplemental Executive Retirement Plan

Q. Please explain the basis for the adjustment you made to the Pension and Benefits operating expenses.

A. I made an adjustment to the Supplemental Executive Retirement Plan ("SERP") portion of the pension and benefits operating expenses.

Q. Please explain your adjustment to the SERP.

A. As explained in the Company's responses to Staff data request 1.81, TEP's test-year payroll loadings include the cost of a SERP. The Company's test-year operating expenses include $927,925 related to the SERP. The SERP is a retirement plan that is provided to a small select group of high-ranking officers of the Company. The high-ranking officers who are covered under the SERP receive these benefits in addition to the regular retirement plan.

Q. Should ratepayers be required to pay the cost of supplemental benefits for the high-ranking officers of the Company?

A. No. The cost of supplemental benefits for high-ranking officers is not a necessary cost of providing electric service. These individuals are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

Q. In recent ACC Decisions did the Commissioners determine whether SERP expenses were recoverable?

A. Yes. Recently, the Commission agreed with RUCO that SERP expenses should not be the burden of ratepayers. In Southwest Gas' latest rate case, (Decision No. 68487, dated February 23, 2006) the Commission agreed with RUCO that SERP should be excluded from operating expenses. In Arizona Public Service's most recent rate case, (Decision No. 69663, dated June 28, 2007), the Commission voted to disallow SERP. Moreover, the Commission voted to disallow SERP in the UNS Gas rate case (Decision No. 70011, dated November 27,2007). I see no reason to depart from this precedent; therefore, RUCO recommends the removal of the test-year cost of the SERP from operating expenses.

As shown on Schedule RLM-8, column (E), this adjustment decreased test-year expenses by $927,925.

Operating Income Adjustment No. 5 – Incentive Compensation

Q. Please provide an explanation for RUCO's adjustment to the incentive compensation expenses.

A. After reviewing the Commission's position on incentive compensation expense as authorized in Decision No. 70011, dated November 27, 2007 (the recent UNS Gas rate case); RUCO recommends a 50/50 sharing as a reasonable balancing of the interests between ratepayers and shareholders. The incentive program is comprised of elements that relate to the Company's financial performance and cost containment goals, matters that primarily benefit shareholders; plus elements based on meeting customer service goals, which offers opportunity for the Company's customers to benefit from improved performance.

RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements. RUCO determined in the instant case the test year was not abnormal; and therefore, RUCO dismisses the Company's proposal to a four-year average of the incentive compensation expenses.

Q. Please explain the elements of your adjustment to the incentive compensation expenses.

A. As shown on Schedule RLM-11, this adjustment consists of two elements. First, I restated the Company's adjusted level of the incentive compensation expense from its proposed four-year average to the actual historical test-year expense level. Second, I split the historical expense level on a 50/50 basis.

As shown on Schedule RLM-8, column (F) and supporting Schedule RLM-11, this adjustment decreased test-year expenses by $1,525,378.

Operating Income Adjustment No. 6 – Rate-Case Expense

Q. Please discuss your review of the Company's proposed rate-case expenses.

A. The Company has budgeted $900,000 for rate-case expenses for outside services and proposes to amortize that amount over four years. RUCO has a concern over the reasonableness of such a large financial burden to the ratepayers from this requested adjustment. RUCO believes the Company's proposed rate-case expense of nearly a million dollars is excessive and should be reduced significantly when compared with rate-case expense allowances in a long line of cases that have come before the Commission.

Unlike the rate-case expenses for TEP's affiliates UNS Gas and UNS Electric where a significant portion of the costs incurred were due to the allocation of TEP personnel assigned to perform tasks associated with those individual rate cases; in the instant case TEP is requesting recovery of $900,000 from outside services. TEP labor costs allocated to UNS Gas' rate case was $476,602 and $256,734 was allocated to UNS Electric.

With consideration of the Commission's authorized level of rate-case expense in the recent UNS Gas rate case (Decision No. 70011) of $300,000, RUCO believes the instant case warrants a reduced level of rate-case expense and recommends a 50 percent adjustment. RUCO has no disagreement with the Company's proposal to amortize the rate-case expense over four years.

Therefore, this adjustment reduces annual rate-case expense from the Company's proposed level of $225,000 ($900,000 / 4 years) to RUCO's recommended level of $112,500 ($450,000 / 4 years).

As shown on Schedule RLM-8, Column (G), this adjustment decreased test-year expenses by $112,500.

Operating Income Adjustment No. 7 – Property Tax

Q. Do you agree with TEP's methodology for computing property taxes?

A. Yes. I have used the same methodology to compute RUCO's recommended level of property taxes.

Q. Please explain the reasons for RUCO's property tax adjustment.

A. My adjustment consists of two elements. First, RUCO's property tax adjustment reflects several adjustments to the net plant in service. Second, RUCO's property tax computation uses a different assessment ratio than the Company.

Q. Please explain the first element of RUCO's property tax adjustment.

A. RUCO made several adjustments to net plant in service. The value of the net plant in service is the initial component in the calculation of the appropriate level of property tax expenses. These net plant adjustments are depicted on Schedule RLM-4. Moreover, to avoid a double count in its calculation of total net plant in service, RUCO reversed additional journal entries for transactions associated with RUCO's plant adjustments. These additional components were identified by the Company in its response to RUCO data request 10.1 in which the Company, by reconciling the rate base, illuminated additional transactions directly related to RUCO's plant adjustments. These additional transactions are depicted on Schedule RLM-12, lines 2 through 7.

Q. Please explain the second element of RUCO's property tax adjustment.

A. The second element of this adjustment results from RUCO's use of an assessment ratio of 23 percent, versus the Company use of a 23.5 percent assessment ratio. RUCO's use of the 23 percent ratio accurately reflects the ratio which will be valid when the authorized rates in this case become effective (January 2009). RUCO's recommendation is also consistent with recent Commission decisions in the Southwest Gas rate case (Decision No. 68487, dated February 23, 2006) and the UNS Gas rate case (Decision No. 70011, dated November 27,2007).

The decreasing assessment ratios as authorized in the Arizona Revised Statues relating to property taxes states the effective rate from December 31, 2008 through December 31, 2009 to be 23 percent. The assessment ratio will continue to decline by one-half percent each year until it reaches 20 percent on December 31, 2014.

As shown on Schedule RLM-8, column (H) and supporting Schedule RLM-12, this adjustment decreased test-year expenses by $1,800,201.

Adjustments To Operating Expenses No. 8 – Overhead Line Maintenance

Q. Please explain the basis for the adjustment you made to overhead line maintenance expense.

A. Through discovery I reviewed and analyzed five years of expenses recorded in FERC account 593 – overhead line maintenance from 2002 through 2006.

My analysis indicated this expense was sufficiently volatile to recommend a test-year adjustment to acknowledge the wide variation in annual costs.

Therefore, my adjusted test-year expense in the instant case is the calculated five-year average of the "inflation adjusted" annual overhead line maintenance expenses for 2002 through 2006.

My adjustment is necessary to normalize the test-year level of overhead maintenance expenses.

As shown on Schedule RLM-8, column (I) and supporting Schedule RLM-13, this adjustment decreased test-year expenses by $126,584.

Adjustments To Operating Expenses No. 9 – Penalties and Fines

Q. Please explain the basis for the adjustment you made to remove expenses for penalties and fines.

A. Through discovery I reviewed the Company's response to Staff Data Request 1.114. My analysis indicated there were three invoices for penalties and fines imposed on TEP that were recorded in test-year operating expenses.

RUCO believes if the Company does not prudently handle its affairs and consequently is imposed penalties and fines imposed, these costs are not the financial responsibility of the ratepayers.

Therefore, as shown on Schedule RLM-8, column (J), this adjustment decreased test-year expenses by $9,433.

Adjustments To Operating Expenses No. 12 – Payroll Expense

Q. Please explain the basis for your adjustment to payroll expenses.

A. RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements.

Since RUCO determined the test year was not abnormal the Company's proposal to average the payroll expense over a two-year period was dismissed.

Therefore, as shown on Schedule RLM-14, I restated the Company's proposed allocation of payroll expenses to reflect the actual historical test-year level of payroll expense.

As shown on Schedule RLM-8, column (M) and supporting Schedule RLM-14, this adjustment restated the Company's proposed allocation of payroll expenses to reflect the actual historical test-year level of payroll expense and thus increased test-year expenses by $19,651.

<u>Adjustments To Operating Expenses No. 13 – Payroll Tax Expense</u>

Q. Please explain the basis for your adjustment to payroll tax expenses.

A. This is a companion adjustment to the payroll expense adjustment and reflects the actual historical test-year level of payroll tax expense.

As shown on Schedule RLM-8, column (N) and supporting Schedule RLM-15, this adjustment restated the Company's proposed allocation of payroll tax expenses to reflect the actual historical test-year level of payroll tax expense and thus increased test-year expenses by $2,689.

Adjustments To Operating Expenses No. 14 – Renewable Resources

Q. Please explain the basis for your adjustment to renewable resources expenses.

A. This is a conforming adjustment corresponding to the Company's response to Staff Data Request 1.85, which acknowledged a failure to remove $19,274 in expenses in the Company's original filing.

Therefore, as shown on Schedule RLM-8, column (O), this adjustment decreased test-year expenses by $19,274.

Adjustments To Operating Expenses No. 17 – Customer Care and Billing

Q. Please explain the basis for your adjustment to normalize the customer care and billing expenses.

A. This adjustment removes the computed incremental cost increase associated with the implementation of a new customer information system, designated as the Customer Care and Billing system ("CC&B").

Q. Please explain why RUCO disallowed increased customer service costs.

A. RUCO is disallowing this expenditure because evidence provided by the Commission Consumer Services Section indicates the quality of customer service has not improved since the CC&B has been implemented. As shown on Attachment A filed at the end of my testimony, the Commission Consumer Services Section Report ("Report") on TEP states, in 2004, there were 9 consumer complaints recorded based on "quality of service" issues. In 2005, there were 25 consumer complaints recorded based on "quality of service" issues. In 2006, the year in which the CC&B was implemented, there were 95 consumer complaints recorded based on "quality of service" issues. In 2007, through to December 3rd, there were 111 consumer complaints recorded based on "quality of service" issues.

Since the Report does not demonstrate the improvements, enhancements and synergy promoted by the Company as justification for the increased expenditure has translated into increased customer satisfaction, RUCO is removing any increase in this expense until the Company provides documentation that the overall customer satisfaction level has improved.

Moreover, this scenario of attempting to improve customer service by implementing a new system to consolidate call centers and customer service functions among UNS Gas, UNS Electric and TEP has not yet proven to provide the significantly enhanced benefit to the ratepayers. As I have previously testified in both the recent UNS Gas and UNS Electric rate cases the additional costs incurred to improve the quality of customer service has not translated into a better level of service; to the contrary, the evidence shows a higher degree of frustration in the quality of service customers received.

Therefore, as shown on Schedule RLM-8, column (R) and supporting Schedule RLM-16, this adjustment decreased test-year expenses by $296,230.

Adjustments To Operating Expenses No. 19 – Employee Recognition

Q. Please explain the basis for your adjustment to operating expenses for the removal of costs associated with employee recognition.

A. As previously explained in Operating Expense Adjustment No. 3, RUCO believes it is inappropriate to burden ratepayers with expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of electric service.

Therefore, RUCO requested the Company to identify costs recorded in the test year associated with employee recognition expenses. In the Company's response to RUCO data request 6.1, TEP acknowledged $76,125 was recorded in the test-year general ledger for employee recognition. The recognition program is administered by the OC Tanner Recognition Company wherein an employee selects his/her service-award gift from a catalogue.

RUCO analyzed the information in the Company's response and determined no portion of the $76,125 has been removed in any other adjustment.

As shown on Schedule RLM-8, column (T), this adjustment decreased test-year expenses by $76,125.

Adjustments To Operating Expenses No. 20 – Employee Benefits

Q. Please explain the basis for your adjustment to operating expenses for the removal of costs associated with some employee benefits.

A. As previously explained in Operating Expense Adjustment No. 3, RUCO believes it is inappropriate to burden ratepayers with expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of electric service.

Meanwhile, Staff had requested that the Company identify costs recorded in the test year associated with employee benefit expenses. In the Company's response to Staff data request 1.79, TEP recognized $54,442 were recorded in the test-year general ledger for employee benefits, such as; gifts, awards, luncheons, dinners, picnics, parties and social events. RUCO analyzed the information provided in the Company's response and determined that of the $54,442, TEP had removed $14,659 from the test-year expenses, RUCO had removed $16,618 from of test-year expenses in previous Adjustment No. 3; thus, leaving $23,165 ($54,442 - $14,659 - $16,618 = $23,165) in costs recorded in the test year associated with employee benefit expenses.

Therefore, as shown on Schedule RLM-8, column (U), this adjustment decreased test-year expenses by $23,165.

<u>Operating Income Adjustment No. 28 – Income Tax Expense</u> – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

As shown on Schedule RLM-7, column (D) and supporting Schedule RLM-17, this adjustment increased test-year expenses by $32,062,674.

**COST OF CAPITAL**

Q. Is RUCO proposing any adjustments to the Company proposed cost of capital?

A. Yes. As shown on Schedule RLM-18, this adjustment decreases the Company's cost of common equity and therefore its weighted cost of capital by 59 basis points from 8.35 to 7.76 percent to reflect current market conditions.

This adjustment is fully explained in the testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your direct testimony?

A. Yes, it does.

## ATTACHMENT A

## MEMORANDUM

TO: Rodney Moore
Rate Analyst
Residential Consumer Utility Office

FROM: John La Porta
Public Utilities Consumer Analyst I
Utilities Division

DATE: December 4, 2007

RE: Tucson Electric Power Company – Quality of Service Complaints

Per your request, a research of the Consumer Services database represents the number of Quality of Service complaints that were filed against Tucson Electric Power Company ("TEP" or "Company") since 2004.

2004 – Nine Complaints - 1 TEP Response Time, 1 Misinformation from Company,
3 Customer Service Contact, 2 Outages, 2 Other

2005 – 25 Complaints - 2 TEP Response Time, 6 Misinformation from Company,
2 Customer Service Contact, 7 Outages,
2 Can't Reach Company, 2 Pressure or Voltage Issues,
4 Other

2006 – 95 Complaints - 5 TEP Response Time, 1 Misinformation from Company,
2 Customer Service Contact, 3 Field Visits by Company,
9 Outages, 69 Can't Reach Company,
2 Pressure or Voltage Issues, 4 Other

2007 – 111 Complaints (thru December 3, 2007) 2 TEP Response Time, 14 Outages,
92 Can't Reach Company, 3 Other

If you need any further information regarding the numbers above, please feel free to call me at (602) 542-0819.

**APPENDIX 1**

Qualifications of Rodney Lane Moore

**EDUCATION:** Athabasca University
Bachelor's Degree in Business Administration - 1993

**EXPERIENCE:** Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona 85007
May 2001 - Present

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

Auditor
Arizona Corporation Commission
Phoenix, Arizona 85007
October 1999 - May 2001

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

**RESUME OF RATE CASE AND REGULATORY PARTICIPATION**

| Utility Company | Docket No. |
|---|---|
| Rio Verde Utilities, Inc | WS-02156A-00-0321 |
| Black Mountain Gas Company | G-03703A-01-0283 |
| Green Valley Water Company | W-02025A-01-0559 |
| New River Utility Company | W-01737A-01-0662 |

| Utility Company | Docket No. |
|---|---|
| Dragoon Water Company | W-01917A-01-0851 |
| Roosevelt Lake Resort, Inc. | W-01958A-02-0283 |
| Southwest Gas Company | G-01551A-02-0425 |
| Arizona-American Water Company | W-01303A-02-0867 et al. |
| Rio Rico Utilities, Inc. | WS-02676A-03-0434 |
| Qwest Corporation | T-01051B-03-0454 |
| Chaparral City Water Company | W-02113A-04-0616 |
| Southwest Gas Company | G-01551A-04-0876 |
| Arizona-American Water Company | W-01303A-05-0405 |
| Far West Water and Sewer Company | WS-03478A-05-0801 |
| Gold Canyon Sewer Company | SW-02519A-06-0015 |
| Arizona-American Water Company | WS-01303A-06-0403 |
| UNS Gas, Inc. | G-04204A-06-0463 et al. |
| UNS Electric, Inc. | E-04204A-06-0783 |

# EXHIBIT A

**TUCSON ELECTRIC POWER COMPANY**

**DATA RESPONSE 1.20 (a): FERC 921 A&G Expense - Office Supplies**

**TEST YEAR ENDING DECEMBER 31, 2006**

Source: Transaction Detail - Co: 002, GL Period Name: %06, FERC: 0921

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 51500 | 123 | Materials Purchased | ALCPA *DUES LB | 185.00 | | 185.00 | | |
| 51500 | 123 | Materials Purchased | AMAZON.COM | 69.95 | | 69.95 | | |
| 51500 | 123 | Materials Purchased | AMY'S HALLMARK #899 | 7.87 | | 7.87 | | |
| 51500 | 123 | Materials Purchased | AMZ*SUPERSTORE | 46.92 | | 46.92 | | |
| 51500 | 123 | Materials Purchased | BRUEGGERS BAGEL BAKERY | 84.31 | | 84.31 | | |
| 51500 | 123 | Materials Purchased | GENL INJECTABLES/VACCI | 309.33 | | 309.33 | | |
| 51500 | 123 | Materials Purchased | GONE SCRAPPIN INC | 450.00 | | 450.00 | | |
| 51500 | 123 | Materials Purchased | HARRY & DAVID #830 | 277.52 | | 277.52 | | |
| 51500 | 123 | Materials Purchased | HENRY SCHEIN* | 128.54 | | 128.54 | | |
| 51500 | 123 | Materials Purchased | ISTOCKPHOTO | 10.00 | | 10.00 | | |
| 51500 | 123 | Materials Purchased | JASON'S DELI | 123.67 | | 123.67 | | |
| 51500 | 123 | Materials Purchased | JUST SPORTS 244 | 107.65 | | 107.65 | | |
| 51500 | 123 | Materials Purchased | MICHAELS #2758 | 23.16 | | 23.16 | | |
| 51500 | 123 | Materials Purchased | MICHAELS #5206 | 160.15 | | 160.15 | | |
| 51500 | 123 | Materials Purchased | MICHAELS #9530 | 113.31 | | 113.31 | | |
| 51500 | 123 | Materials Purchased | MINKUS ADVERTISING | 270.20 | | 270.20 | | |
| 51500 | 123 | Materials Purchased | MISTERART.COM LP | 34.24 | | 34.24 | | |
| 51500 | 123 | Materials Purchased | MOUNTAIN VIEW SPORTS | 190.34 | | 190.34 | | |
| 51500 | 123 | Materials Purchased | NELLIS AFB EXCHANGE | 49.95 | | 49.95 | | |
| 51500 | 123 | Materials Purchased | NEW BEGINNINGS | 150.00 | | 150.00 | | |
| 51500 | 123 | Materials Purchased | OMAHASTEAKS.COM INC | 747.96 | | 747.96 | | |
| 51500 | 123 | Materials Purchased | ORIENTAL TRADING CO | 187.91 | | 187.91 | | |
| 51500 | 123 | Materials Purchased | OSCO DRUG 9215 | 276.88 | | 276.88 | | |
| 51500 | 123 | Materials Purchased | OSCO DRUG 9254 | 10.21 | | 10.21 | | |
| 51500 | 123 | Materials Purchased | OSCO DRUG 9277 | 21.07 | | 21.07 | | |
| 51500 | 123 | Materials Purchased | PARADIES WASH NAT L | 4.70 | | 4.70 | | |
| 51500 | 123 | Materials Purchased | PARADIES-TUCSON | 6.21 | | 6.21 | | |
| 51500 | 123 | Materials Purchased | PARK PLACE | 101.50 | | 101.50 | | |
| 51500 | 123 | Materials Purchased | PARTY AMERICA #1404 | 89.81 | | 89.81 | | |
| 51500 | 123 | Materials Purchased | PARTY AMERICA 1405 | 186.09 | | 186.09 | | |
| 51500 | 123 | Materials Purchased | PARTY CITY OF TUCSON I | 449.15 | | 449.15 | | |
| 51500 | 123 | Materials Purchased | PEN*POWERGEN | 95.00 | | 95.00 | | |
| 51500 | 123 | Materials Purchased | PLAYHARD, INC | 78.80 | | 78.80 | | |
| 51500 | 123 | Materials Purchased | POSITIVE PROMOTIONS IN | 1,049.80 | | 1,049.80 | | |
| 51500 | 123 | Materials Purchased | PRIMERA WEB STORE | 284.86 | | 284.86 | | |
| 51500 | 123 | Materials Purchased | ROCKY MT ELEC LEAGUE | 410.00 | | 410.00 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 51500 | 123 | Materials Purchased | SAFEWAY STORE00015214 | 54.95 | | 54.95 | | |
| 51500 | 123 | Materials Purchased | SAFEWAY STORE 00019SC9 | 648.77 | | 648.77 | | |
| 51500 | 123 | Materials Purchased | SAHUARO TROPHY | 107.60 | | 107.60 | | |
| 51500 | 123 | Materials Purchased | SCHLOTZSKY S | 9.71 | | 9.71 | | |
| 51500 | 123 | Materials Purchased | SEARS ROEBUCK 1338 | 69.93 | | 69.93 | | |
| 51500 | 123 | Materials Purchased | SKYLINE GALLERY | 500.00 | | 500.00 | | |
| 51500 | 123 | Materials Purchased | SONARE 20075396 | 429.25 | | 429.25 | | |
| 51500 | 123 | Materials Purchased | SPINKEEPER.COM | 569.94 | | 569.94 | | |
| 51500 | 123 | Materials Purchased | STARBAND | 1,439.88 | | 1,439.88 | | |
| 51500 | 123 | Materials Purchased | TARGET 00001792 | 43.22 | | 43.22 | | |
| 51500 | 123 | Materials Purchased | TARGET 00002113 | 64.82 | | 64.82 | | |
| 51500 | 123 | Materials Purchased | TARGET 00008540 | 98.67 | | 98.67 | | |
| 51500 | 123 | Materials Purchased | TARGET 00008557 | 10.75 | | 10.75 | | |
| 51500 | 123 | Materials Purchased | TARGET 00013169 | 247.28 | | 247.28 | | |
| 51500 | 123 | Materials Purchased | TARGET 00014399 | 317.86 | | 317.86 | | |
| 51500 | 123 | Materials Purchased | TARGET 00018630 | 14.04 | | 14.04 | | |
| 51500 | 123 | Materials Purchased | TAYLOR DISTRIBUTOR INC | 163.55 | | 163.55 | | |
| 51500 | 123 | Materials Purchased | THE GIFT BASKET STOP | 99.45 | | 99.45 | | |
| 51500 | 123 | Materials Purchased | THE SPORTS AUTHORITY # | 87.54 | | 87.54 | | |
| 51500 | 123 | Materials Purchased | THRIFT CITY & OUTLET | 27.15 | | 27.15 | | |
| 51500 | 123 | Materials Purchased | TOYS R US #5646 | 27.01 | | 27.01 | | |
| 51500 | 123 | Materials Purchased | TUCSON MALL | 1,081.50 | | 1,081.50 | | |
| 51500 | 123 | Materials Purchased | TUCSONS MAP AND FLAG C | 64.45 | | 64.45 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AWAR | 229.19 | | 229.19 | | |
| 51500 | 123 | Materials Purchased | WAL MART | 155.47 | | 155.47 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00002Q39 | 77.34 | | 77.34 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00038Q39 | 21.26 | | 21.26 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00040Q39 | 10.21 | | 10.21 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00047Q39 | 3.76 | | 3.76 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00052Q39 | 13.92 | | 13.92 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00053Q39 | 15.80 | | 15.80 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00065Q39 | 24.70 | | 24.70 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00067Q39 | 615.70 | | 615.70 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00070Q39 | 5.53 | | 5.53 | | |
| 51500 | 123 | Materials Purchased | WAL-MART #1175 | 5.00 | | 5.00 | | |
| 51500 | 123 | Materials Purchased | WAL-MART #1291 | 90.12 | | 90.12 | | |
| 51500 | 123 | Materials Purchased | WAL-MART #1325 | 82.25 | | 82.25 | | |
| 51500 | 123 | Materials Purchased | WAL-MART #2922 SE2 | 15.44 | | 15.44 | | |
| 51500 | 123 | Materials Purchased | WORLD MKT 00001370 | 217.44 | | 217.44 | | |
| 51500 | 123 | Materials Purchased | WORLD MKT 00002691 | 129.99 | | 129.99 | | |
| 51500 | 123 | Materials Purchased | | 263.00 | | 263.00 | VOLUNTEERS OF | 062706 26300 |
| 79010 | 282 | Meals & Ent - Discretionary | ALBERTSONS #959 S9H | 284.97 | | 284.97 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ALBERTSONS #963 | 27.27 | | 27.27 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 282 | Meals & Ent - Discretionary | ALBERTSONS #988 S9H | 127.97 | | 127.97 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ALVERNON DONUT SHOP | 52.07 | | 52.07 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ALVERNON DONUTS | 19.76 | | 19.76 | | |
| 79010 | 282 | Meals & Ent - Discretionary | AMC VALLEY VIE01001Q02 | 9.00 | | 9.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | APPLEBEE'S #602 | 62.95 | | 62.95 | | |
| 79010 | 282 | Meals & Ent - Discretionary | APPLEBEE'S MEN00164087 | 27.89 | | 27.89 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ASSOCTD BLDRS/CNTRC ED | 136.00 | | 136.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | AZ DIAMONDBACKS BX OFC | 780.00 | | 780.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | AZ DIAMONDBACKS SPRING | 1,483.00 | | 1,483.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BAGGINS STORE #10 | 645.57 | | 645.57 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BAHAMA BREEZE 00030114 | 13.84 | | 13.84 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BAL O'S DSA | 54.00 | | 54.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BAMBOO TEMPE | 13.57 | | 13.57 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BAMBOO TERRACE RESTAUR | 87.00 | | 87.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BAMBOO TUCSON | 69.75 | | 69.75 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BARLEY BROTHERS BREWER | 129.18 | | 129.18 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BASHA S #88 SYW | 17.59 | | 17.59 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BASHAS #100 | 35.75 | | 35.75 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BASHAS #100 SYW | 119.79 | | 119.79 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BASKIN ROBBINS #251 | 56.90 | | 56.90 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BEDROXX | 137.21 | | 137.21 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BENNIGANS GRILL AND TA | 24.11 | | 24.11 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BOOGA REDS | 63.99 | | 63.99 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BRUEGGERS BAGEL BAKERY | 10.58 | | 10.58 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BRUEGGER'S BAGELS -Q50 | 36.87 | | 36.87 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BURGER KING # 1002 Q07 | 9.49 | | 9.49 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BURGER KING #8615 Q07 | 9.34 | | 9.34 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BUSY B S BAKERY | 22.37 | | 22.37 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CAFE POCA COSA | 148.00 | | 148.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CALIFORNIA PIZZA 058 | 79.79 | | 79.79 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CALLAWAY INN FRONT DES | 117.72 | | 117.72 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CAPITAL GRILLE 800 | 44.85 | | 44.85 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CASA BONITA | 44.39 | | 44.39 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CHA-BONES | 20.00 | | 20.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CHARIOT PIZZA | 657.68 | | 657.68 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CHARLIECLARK'SSTEAKHOU | 119.86 | | 119.86 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CHEVRON 0092528 Q61 | 12.21 | | 12.21 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CHILI'S GRI16100011619 | 9.88 | | 9.88 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CHILI'S GRI56300005637 | 233.77 | | 233.77 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CIRCLE K 00424 Q04 | 7.56 | | 7.56 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CITY OF TCSN RAND CLBH | 50.00 | | 50.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CLAIM JUMPER #35 | 1,307.93 | | 1,307.93 | | |
| 79010 | 282 | Meals & Ent - Discretionary | COFFEE POT RESTAURANT | 9.71 | | 9.71 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 282 | Meals & Ent - Discretionary | COUNTY LINE RIVERWALK | 24.36 | | 24.36 | | |
| 79010 | 282 | Meals & Ent - Discretionary | CRACKER BARREL #416 | 9.45 | | 9.45 | | |
| 79010 | 282 | Meals & Ent - Discretionary | DELECTABLES RESTAURANT | 945.78 | | 945.78 | | |
| 79010 | 282 | Meals & Ent - Discretionary | DENNY'S #6608 Q67 | 12.01 | | 12.01 | | |
| 79010 | 282 | Meals & Ent - Discretionary | DESERT DIAMOND CASINO | 28.90 | | 28.90 | | |
| 79010 | 282 | Meals & Ent - Discretionary | DISCOUNT COFFEE COM | 555.86 | | 555.86 | | |
| 79010 | 282 | Meals & Ent - Discretionary | DORAL EAGLEWOOD | 38.21 | | 38.21 | | |
| 79010 | 282 | Meals & Ent - Discretionary | EAT AT JOE'S AIRPORT | 7.05 | | 7.05 | | |
| 79010 | 282 | Meals & Ent - Discretionary | EL MINUTO CAFE | 29.00 | | 29.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | EL MOLINITO | 833.15 | | 833.15 | | |
| 79010 | 282 | Meals & Ent - Discretionary | EL PARADOR | 477.78 | | 477.78 | | |
| 79010 | 282 | Meals & Ent - Discretionary | EL PASO BAR B QUE | 29.40 | | 29.40 | | |
| 79010 | 282 | Meals & Ent - Discretionary | EL PASO BAR-B-QUE 555 | 313.01 | | 313.01 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ELA THE FAT BURRITO | 10.98 | | 10.98 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ELEPHANT & CASTLE | 52.16 | | 52.16 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ELEPHANT BAR # 219 | 36.16 | | 36.16 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ENOTECA PIZZARIA WINE | 73.81 | | 73.81 | | |
| 79010 | 282 | Meals & Ent - Discretionary | FAMOUS SAMS #17 | 18.28 | | 18.28 | | |
| 79010 | 282 | Meals & Ent - Discretionary | FIRECRACKER | 91.41 | | 91.41 | | |
| 79010 | 282 | Meals & Ent - Discretionary | FLEMINGS #1350 | 254.44 | | 254.44 | | |
| 79010 | 282 | Meals & Ent - Discretionary | FRIDAYS_AM_BAR #0806 | 10.77 | | 10.77 | | |
| 79010 | 282 | Meals & Ent - Discretionary | FRYS-FOOD-DRG #0090SXN | 141.61 | | 141.61 | | |
| 79010 | 282 | Meals & Ent - Discretionary | FRYS-FOOD-DRG #058 SXN | 498.95 | | 498.95 | | |
| 79010 | 282 | Meals & Ent - Discretionary | GASLIGHT THEATRE | 720.06 | | 720.06 | | |
| 79010 | 282 | Meals & Ent - Discretionary | GOLDEN CORRAL 29724Q15 | 25.46 | | 25.46 | | |
| 79010 | 282 | Meals & Ent - Discretionary | GREATER TUCSON LEADER | 35.00 | | 35.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | GREER LODGE | 16.11 | | 16.11 | | |
| 79010 | 282 | Meals & Ent - Discretionary | Gross Pay | 46,485.77 | | 46,485.77 | | |
| 79010 | 282 | Meals & Ent - Discretionary | GUILLERMOS DOUBLE L RE | 80.33 | | 80.33 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HMS HOST-ORD-AIRPT #55 | 9.46 | | 9.46 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HMSHOST-LAS-AIRPT #008 | 8.06 | | 8.06 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HMSHOST-PHX-AIR #05 | 11.97 | | 11.97 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HOMETOWN BUFFE00103Q31 | 43.21 | | 43.21 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HONEYBAKED-HAM #0053 | 157.99 | | 157.99 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HOOTERS OF SAN DIEGO | 18.33 | | 18.33 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HOTEL CONTESSA | 13.89 | | 13.89 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HOTEL CONTESSA-HOTEL | 63.43 | | 63.43 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HUDDLE HOUSE #358 | 17.93 | | 17.93 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HYATT HOTELS F & B | 24.87 | | 24.87 | | |
| 79010 | 282 | Meals & Ent - Discretionary | HYATT HOTELS DENVER CC | 47.08 | | 47.08 | | |
| 79010 | 282 | Meals & Ent - Discretionary | IHOP #3033 | 14.92 | | 14.92 | | |
| 79010 | 282 | Meals & Ent - Discretionary | IHOP#3036 | 75.75 | | 75.75 | | |
| 79010 | 282 | Meals & Ent - Discretionary | IN-N-OUT BURGER 000000 | 9.49 | | 9.49 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 282 | Meals & Ent - Discretionary | IN-N-OUT BURGERS | 6.94 | | 6.94 | | |
| 79010 | 282 | Meals & Ent - Discretionary | JACKSONS GRILL | 210.60 | | 210.60 | | |
| 79010 | 282 | Meals & Ent - Discretionary | JASON'S DELI | 1,223.56 | | 1,223.56 | | |
| 79010 | 282 | Meals & Ent - Discretionary | JB'S RESTAURANT 35 | 19.28 | | 19.28 | | |
| 79010 | 282 | Meals & Ent - Discretionary | JOE'S ON SULLIVAN | 36.56 | | 36.56 | | |
| 79010 | 282 | Meals & Ent - Discretionary | JOHNNY ROCKETS | 48.85 | | 48.85 | | |
| 79010 | 282 | Meals & Ent - Discretionary | KFC #10 Q20 | 16.25 | | 16.25 | | |
| 79010 | 282 | Meals & Ent - Discretionary | KMART 00049Q | 21.96 | | 21.96 | | |
| 79010 | 282 | Meals & Ent - Discretionary | KOFA CAFE | 7.58 | | 7.58 | | |
| 79010 | 282 | Meals & Ent - Discretionary | KRISPY KREME 15 05 | 88.13 | | 88.13 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LA CASITA CAFE | 31.71 | | 31.71 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LA HACIENDA EXPRESS | 6.51 | | 6.51 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LESLEE'S CAFE Q99 | 5.25 | | 5.25 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LEVY @BANK1 BPARK CON | 225.00 | | 225.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LEVY GRP SALE 90085002 | 831.03 | | 831.03 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LIGHTNING RIDGE CAFE | 1,160.61 | | 1,160.61 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LIONS DEN, THE | 10.50 | | 10.50 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LITTLE MEXICO RESTAURA | 184.17 | | 184.17 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LODGE ON THE DESERT | 445.46 | | 445.46 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LOEWS #698 FOOTHILLS | 102.00 | | 102.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | MACARONI GR16300001636 | 336.56 | | 336.56 | | |
| 79010 | 282 | Meals & Ent - Discretionary | MANUEL'S AMIGOS CA | 29.78 | | 29.78 | | |
| 79010 | 282 | Meals & Ent - Discretionary | MCALISTER'S DELI #1205 | 21.93 | | 21.93 | | |
| 79010 | 282 | Meals & Ent - Discretionary | MCDONALD'S F18788 Q17 | 11.22 | | 11.22 | | |
| 79010 | 282 | Meals & Ent - Discretionary | MCDONALDS F5012 Q17 | 3.49 | | 3.49 | | |
| 79010 | 282 | Meals & Ent - Discretionary | MCDONALD'S F6045 Q17 | 16.62 | | 16.62 | | |
| 79010 | 282 | Meals & Ent - Discretionary | METRO GRILL PARK PLACE | 95.94 | | 95.94 | | |
| 79010 | 282 | Meals & Ent - Discretionary | MICHAS | 127.49 | | 127.49 | | |
| 79010 | 282 | Meals & Ent - Discretionary | MOODY GARDENS, INC | 12.77 | | 12.77 | | |
| 79010 | 282 | Meals & Ent - Discretionary | NADINES PASTRY SHOPPE | 70.20 | | 70.20 | | |
| 79010 | 282 | Meals & Ent - Discretionary | NEW YORK PIZZA DEPT | 7.73 | | 7.73 | | |
| 79010 | 282 | Meals & Ent - Discretionary | OAK CREEK BREWERY & GR | 33.92 | | 33.92 | | |
| 79010 | 282 | Meals & Ent - Discretionary | OAXACA RESTAURANTE | 29.73 | | 29.73 | | |
| 79010 | 282 | Meals & Ent - Discretionary | OISHI SUSHI & TERIYAKI | 91.50 | | 91.50 | | |
| 79010 | 282 | Meals & Ent - Discretionary | OLD CHICAGO PASTA & PI | 23.68 | | 23.68 | | |
| 79010 | 282 | Meals & Ent - Discretionary | OLD PUEBLO GRILLE | 1,373.94 | | 1,373.94 | | |
| 79010 | 282 | Meals & Ent - Discretionary | OMNI HOTELS INTERLOCKE | 73.15 | | 73.15 | | |
| 79010 | 282 | Meals & Ent - Discretionary | PALO VERDE BAR & GRILL | 85.70 | | 85.70 | | |
| 79010 | 282 | Meals & Ent - Discretionary | PEI WEI ASIAN DINER-00 | 185.55 | | 185.55 | | |
| 79010 | 282 | Meals & Ent - Discretionary | PIZZA HUT #14357500Q34 | 515.59 | | 515.59 | | |
| 79010 | 282 | Meals & Ent - Discretionary | PIZZA HUT #14357543Q | 45.38 | | 45.38 | | |
| 79010 | 282 | Meals & Ent - Discretionary | QUIZNOS SUB #3255 Q22 | 16.80 | | 16.80 | | |
| 79010 | 282 | Meals & Ent - Discretionary | RAINFOREST-GALVSTN RST | 18.57 | | 18.57 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 282 | Meals & Ent - Discretionary | RENDEZVOUS DINER | 26.84 | | 26.84 | | |
| 79010 | 282 | Meals & Ent - Discretionary | RINCON MARKET | 1,688.26 | | 1,688.26 | | |
| 79010 | 282 | Meals & Ent - Discretionary | RINCON MARKET SRI | 18.07 | | 18.07 | | |
| 79010 | 282 | Meals & Ent - Discretionary | RISKY BUSINESS #4 | 805.37 | | 805.37 | | |
| 79010 | 282 | Meals & Ent - Discretionary | RUDYS CARLISLE#9102Q23 | 11.45 | | 11.45 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SACHIKO SUSHI II | 131.00 | | 131.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAFEWAY STORE00012294 | 38.27 | | 38.27 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAFEWAY STORE00012SC9 | 10.18 | | 10.18 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAFEWAY STORE00017491 | 49.47 | | 49.47 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAFEWAY STORE00017SC9 | 92.19 | | 92.19 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAFEWAY STORE00018SC9 | 604.31 | | 604.31 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAFEWAY STORE 00019SC9 | 197.73 | | 197.73 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SA-ING THAI CUISINE | 19.36 | | 19.36 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SALT WATER GRILL | 104.56 | | 104.56 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SALTGRASS-GALVESTON | 153.75 | | 153.75 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAM HUGHES PLACE | 44.80 | | 44.80 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAUSAGE DELI | 120.30 | | 120.30 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SHEPSOFCHLORIDE | 31.88 | | 31.88 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SILVER SADDLE STEAKHOU | 40.38 | | 40.38 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SPICES | 29.65 | | 29.65 | | |
| 79010 | 282 | Meals & Ent - Discretionary | STAGE COACH GRILL AND | 35.05 | | 35.05 | | |
| 79010 | 282 | Meals & Ent - Discretionary | STARBUCKS USA 00063Q48 | 8.02 | | 8.02 | | |
| 79010 | 282 | Meals & Ent - Discretionary | STARR PASS GOLF CLUB | 548.76 | | 548.76 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SUBWAY 34169 00341Q16 | 32.50 | | 32.50 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SULLIVAN'S STE00085258 | 444.03 | | 444.03 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SUSHI CHO | 24.27 | | 24.27 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SUSHI TEN | 118.62 | | 118.62 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SWEET TOMATOES #48 | 38.22 | | 38.22 | | |
| 79010 | 282 | Meals & Ent - Discretionary | TACO BELL PIZZ49695Q34 | 5.94 | | 5.94 | | |
| 79010 | 282 | Meals & Ent - Discretionary | TED'S COUNTRY STORE | 4,731.83 | | 4,731.83 | | |
| 79010 | 282 | Meals & Ent - Discretionary | TERRIBLES #148 | 14.90 | | 14.90 | | |
| 79010 | 282 | Meals & Ent - Discretionary | TEXAS LAND & CATTLE#71 | 58.62 | | 58.62 | | |
| 79010 | 282 | Meals & Ent - Discretionary | THE GOOD EGG WILLIAMS | 23.97 | | 23.97 | | |
| 79010 | 282 | Meals & Ent - Discretionary | THE MONKEY BOX | 37.82 | | 37.82 | | |
| 79010 | 282 | Meals & Ent - Discretionary | THE OLIVE GARD00016220 | 25.30 | | 25.30 | | |
| 79010 | 282 | Meals & Ent - Discretionary | THE PASTA HOUSE | 35.00 | | 35.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | THE PINES GOLF CLUB AT | 74.59 | | 74.59 | | |
| 79010 | 282 | Meals & Ent - Discretionary | THE SAN LUIS HOTEL | 9.50 | | 9.50 | | |
| 79010 | 282 | Meals & Ent - Discretionary | TIERRA LINDA DESIGNS I | 1,168.40 | | 1,168.40 | | |
| 79010 | 282 | Meals & Ent - Discretionary | Transfer costs from O&M to capital | | 3,988.44 | (3,988.44) | | |
| 79010 | 282 | Meals & Ent - Discretionary | TUBAC MANAGEMENT C | 29.72 | | 29.72 | | |
| 79010 | 282 | Meals & Ent - Discretionary | TUCSON CONVENTION CTR | 153.00 | | 153.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | UNO CHICAGO BAR & GRIL | 42.98 | | 42.98 | | |
| 79010 | 282 | Meals & Ent - Discretionary | VILLAGE-INN-REST #0394 | 17.83 | | 17.83 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 282 | Meals & Ent - Discretionary | WHATABURGER 813 Q26 | 8.74 | | 8.74 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ZUNI GRILL | 26.68 | | 26.68 | | |
| 79010 | 282 | Meals & Ent - Discretionary | | 17,388.66 | | 17,388.66 | | |
| 79010 | 282 | Meals & Ent - Discretionary | | | 17,388.66 | (17,388.66) | | |
| 79010 | 282 | Meals & Ent - Discretionary | | | 100.69 | (100.69) | | |
| 79010 | 282 | Meals & Ent - Discretionary | | 7,489.87 | | 7,489.87 | | |
| 79010 | 282 | Meals & Ent - Discretionary | | 100.69 | | 100.69 | | |
| 79010 | 282 | Meals & Ent - Discretionary | | 450.00 | | 450.00 | CEREMONY | 102706 45000 |
| 79010 | 282 | Meals & Ent - Discretionary | | 3,968.84 | | 3,968.84 | AT REID PARK LLC L | 062006 396884 |
| 79010 | 282 | Meals & Ent - Discretionary | | 761.56 | | 761.56 | CLUB | 21362 |
| 79010 | 282 | Meals & Ent - Discretionary | | 100.69 | | 100.69 | CLUB | 19098 |
| 79010 | 282 | Meals & Ent - Discretionary | | 1,264.60 | | 1,264.60 | CLUB | 120406 126460 |
| 79010 | 282 | Meals & Ent - Discretionary | | 243.16 | | 243.16 | CLUB | 110206 24316 |
| 79010 | 282 | Meals & Ent - Discretionary | | 1,850.00 | | 1,850.00 | CLUB | 100206 185000 |
| 79010 | 282 | Meals & Ent - Discretionary | | 475.74 | | 475.74 | CLUB | 090106 47574 |
| 79010 | 282 | Meals & Ent - Discretionary | | 42.85 | | 42.85 | CLUB | 080206 4285 |
| 79010 | 282 | Meals & Ent - Discretionary | | 224.67 | | 224.67 | CLUB | 070306 22467 |
| 79010 | 282 | Meals & Ent - Discretionary | | 219.50 | | 219.50 | CLUB | 22599 |
| 79010 | 282 | Meals & Ent - Discretionary | | 580.18 | | 580.18 | CLUB | 010406 58018 |
| 79010 | 282 | Meals & Ent - Discretionary | | 360.21 | | 360.21 | CLUB | 030306 36021 |
| 79010 | 282 | Meals & Ent - Discretionary | | 90.00 | | 90.00 | PETTY CASH | RPC43268NICKERSON |
| 79010 | 282 | Meals & Ent - Discretionary | | 1,115.77 | | 1,115.77 | LLC | 454 |
| 79010 | 282 | Meals & Ent - Discretionary | | 35,816.45 | | 35,816.45 | STEIN ERIKSEN LODGE | 2850 |
| 79010 | 282 | Meals & Ent - Discretionary | | 25.00 | | 25.00 | APPRENTICESHIP | 122906 2500 |
| 79010 | 284 | Meals & Ent - NonDiscretionary | BENNIGANS | 87.06 | | 87.06 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | CAFE POCA COSA | 113.29 | | 113.29 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | EINSTEIN BROS #3064 | 12.72 | | 12.72 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | EL MOLINITO | 200.00 | | 200.00 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | EL PASO BAR-B-QUE 555 | 77.89 | | 77.89 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | FOX & HOUND #65057 | 52.37 | | 52.37 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | JASON'S DELI | 147.87 | | 147.87 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | LIGHTNING RIDGE CAFE | 390.60 | | 390.60 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | LUCKY WISHBONE NO. | 64.56 | | 64.56 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | MAINSTREET GRILL, | 37.19 | | 37.19 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | OLD PUEBLO GRILLE | 25.94 | | 25.94 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | PARTY AMERICA | 76.34 | | 76.34 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | SILVER SADDLE STEAKHOU | 20.00 | | 20.00 | | |
| 79010 | 284 | Meals & Ent - NonDiscretionary | WM SUPERCENTER SE2 | 15.00 | | 15.00 | | |
| 79020 | 252 | Member Dues - Individual | 100 CLUB | 560.00 | | 560.00 | | |
| 79020 | 252 | Member Dues - Individual | 88-CRIME INC | 1,000.00 | | 1,000.00 | | |
| 79020 | 252 | Member Dues - Individual | 9210150190MB | 211.35 | | 211.35 | | |
| 79020 | 252 | Member Dues - Individual | 9210150190MB 4026 | 339.40 | | 339.40 | | |
| 79020 | 252 | Member Dues - Individual | 9210150350MB | 160.00 | | 160.00 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79020 | 252 | Member Dues - Individual | 9210250151MB | 252.00 | | 252.00 | | |
| 79020 | 252 | Member Dues - Individual | 9210250190MB | 456.35 | | 456.35 | | |
| 79020 | 252 | Member Dues - Individual | 9210250340MB | 315.00 | | 315.00 | | |
| 79020 | 252 | Member Dues - Individual | 9210250350MB | 145.00 | | 145.00 | | |
| 79020 | 252 | Member Dues - Individual | ACFE | 280.00 | | 280.00 | | |
| 79020 | 252 | Member Dues - Individual | ACGIH | 159.00 | | 159.00 | | |
| 79020 | 252 | Member Dues - Individual | ALCPA *DUES LB | 185.00 | | 185.00 | | |
| 79020 | 252 | Member Dues - Individual | AMERICAN ASSO OF OC | 205.00 | | 205.00 | | |
| 79020 | 252 | Member Dues - Individual | AMERICAN HEART ASSOCIA | 500.00 | | 500.00 | | |
| 79020 | 252 | Member Dues - Individual | ARIZONA ASSOCIATION OF | 780.00 | | 780.00 | | |
| 79020 | 252 | Member Dues - Individual | ARIZONA CHAMBER OF COM | 4,825.00 | | 4,825.00 | | |
| 79020 | 252 | Member Dues - Individual | ARTHRITIS FOUNDATION | 2,000.00 | | 2,000.00 | | |
| 79020 | 252 | Member Dues - Individual | ASID | 415.00 | | 415.00 | | |
| 79020 | 252 | Member Dues - Individual | ASID ONLINE | 435.00 | | 435.00 | | |
| 79020 | 252 | Member Dues - Individual | ASIS | 855.00 | | 855.00 | | |
| 79020 | 252 | Member Dues - Individual | ASSOCIATION OF00 OF 00 | 1,590.00 | | 1,590.00 | | |
| 79020 | 252 | Member Dues - Individual | AZ MX COMMISSION | 133.37 | | 133.37 | | |
| 79020 | 252 | Member Dues - Individual | BIG BROTHERS BIG SISTE | 3,000.00 | | 3,000.00 | | |
| 79020 | 252 | Member Dues - Individual | CASA DE LOS NINOS | 1,000.00 | | 1,000.00 | | |
| 79020 | 252 | Member Dues - Individual | CFA INSTITUTE (INT) | 600.00 | | 600.00 | | |
| 79020 | 252 | Member Dues - Individual | CHICAHOS POR LA CAUSA | 175.00 | | 175.00 | | |
| 79020 | 252 | Member Dues - Individual | EPILEPSY FONDATION OF | 250.00 | | 250.00 | | |
| 79020 | 252 | Member Dues - Individual | IEEE-RENEW | 162.00 | | 162.00 | | |
| 79020 | 252 | Member Dues - Individual | IFMA | 327.00 | | 327.00 | | |
| 79020 | 252 | Member Dues - Individual | IIDA | 872.00 | | 872.00 | | |
| 79020 | 252 | Member Dues - Individual | IOMA | 301.95 | | 301.95 | | |
| 79020 | 252 | Member Dues - Individual | ISACA/ITGI | 150.00 | | 150.00 | | |
| 79020 | 252 | Member Dues - Individual | MOTHERS AGAINST DRUNK | 120.00 | | 120.00 | | |
| 79020 | 252 | Member Dues - Individual | NATIONAL SAFETY COUNCI | 100.00 | | 100.00 | | |
| 79020 | 252 | Member Dues - Individual | NATIONAL SAFETY MANAGE | 70.00 | | 70.00 | | |
| 79020 | 252 | Member Dues - Individual | NCIDQ | 52.00 | | 52.00 | | |
| 79020 | 252 | Member Dues - Individual | OUR TOWN FAMILY CENTER | 250.00 | | 250.00 | | |
| 79020 | 252 | Member Dues - Individual | PASSONLINE.COM | 59.95 | | 59.95 | | |
| 79020 | 252 | Member Dues - Individual | PHOENIX CHAMBER OF COM | 1,000.00 | | 1,000.00 | | |
| 79020 | 252 | Member Dues - Individual | PIMA AIR MUSEUM | 350.00 | | 350.00 | | |
| 79020 | 252 | Member Dues - Individual | PIMA COUNTY BAR ASSOCI | 110.00 | | 110.00 | | |
| 79020 | 252 | Member Dues - Individual | PROJECT MANAGEMENT INS | 844.00 | | 844.00 | | |
| 79020 | 252 | Member Dues - Individual | RESNET | 1,250.00 | | 1,250.00 | | |
| 79020 | 252 | Member Dues - Individual | SHRM ORG | 210.00 | | 210.00 | | |
| 79020 | 252 | Member Dues - Individual | THE AP NETWORK | 595.00 | | 595.00 | | |
| 79020 | 252 | Member Dues - Individual | THE NATURE CONSERVANCY | 25.00 | | 25.00 | | |
| 79020 | 252 | Member Dues - Individual | TUCSON HISPANIC CHAMBE | 3,100.00 | | 3,100.00 | | |
| 79020 | 252 | Member Dues - Individual | TUCSON METRO CHMBR CMM | 108.00 | | 108.00 | | |
| 79020 | 252 | Member Dues - Individual | U OF A FOUNDATION | 395.00 | | 395.00 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79020 | 252 | Member Dues - Individual | WESTERN GOVERNORS' ASS | 550.00 | | 550.00 | | |
| 79020 | 252 | Member Dues - Individual | YALE CLUB OF NYC | 569.31 | | 569.31 | | |
| 79020 | 252 | Member Dues - Individual | | 150.00 | | 150.00 | BG'S | 082806 15000 |
| 79020 | 252 | Member Dues - Individual | | 240.00 | | 240.00 | BREAKFAST CLUB | 071006 24000 |
| 79020 | 252 | Member Dues - Individual | | 240.00 | | 240.00 | BREAKFAST CLUB | 062806 24000 |
| 79020 | 252 | Member Dues - Individual | | 240.00 | | 240.00 | BREAKFAST CLUB | 010406 24000 |
| 79020 | 252 | Member Dues - Individual | | 500.00 | | 500.00 | DM 50 | 121806 50000 |
| 79020 | 252 | Member Dues - Individual | | 500.00 | | 500.00 | DM 50 | 040406 50000 |
| 79020 | 252 | Member Dues - Individual | | 1,500.00 | | 1,500.00 | RESNET | 030906 150000 |
| 79020 | 252 | Member Dues - Individual | | 15,000.00 | | 15,000.00 | RMEL_ENDATED | 121906 1500000 |
| 79020 | 252 | Member Dues - Individual | | 5,000.00 | | 5,000.00 | ALLIANCE_ENDATED | 010506 500000 |
| 79200 | 299 | Miscellaneous | 1-800-FLOWERS.COM,INC. | 83.22 | | 83.22 | | |
| 79200 | 299 | Miscellaneous | ARIZONA CORPORATION CO | 738.00 | | 738.00 | | |
| 79200 | 299 | Miscellaneous | BRUEGGERS BAGEL BAKERY | 87.64 | | 87.64 | | |
| 79200 | 299 | Miscellaneous | CAMPBELL FLORAL&PLA | 79.94 | | 79.94 | | |
| 79200 | 299 | Miscellaneous | CASAS ADOBES FLOWER SH | 87.19 | | 87.19 | | |
| 79200 | 299 | Miscellaneous | CITY OF TUCSON DLNQ AC | 187.53 | | 187.53 | | |
| 79200 | 299 | Miscellaneous | DELIGHTFUL DELIVERIES | 81.97 | | 81.97 | | |
| 79200 | 299 | Miscellaneous | DISCOUNT COFFEE COM | 265.36 | | 265.36 | | |
| 79200 | 299 | Miscellaneous | DOLRTREE 2635 00026351 | 32.43 | | 32.43 | | |
| 79200 | 299 | Miscellaneous | EVERGREEN FLOWERS | 31.18 | | 31.18 | | |
| 79200 | 299 | Miscellaneous | FCC- | 230.00 | | 230.00 | | |
| 79200 | 299 | Miscellaneous | FRAN'S FLOWERS | 65.00 | | 65.00 | | |
| 79200 | 299 | Miscellaneous | FRYS-FOOD-DRG #058 SXN | 459.87 | | 459.87 | | |
| 79200 | 299 | Miscellaneous | FTD*FLOWERS ACROSS AME | 58.94 | | 58.94 | | |
| 79200 | 299 | Miscellaneous | FTD*FTD.COM/1-800-SEND | 83.79 | | 83.79 | | |
| 79200 | 299 | Miscellaneous | FTD*ROSES & MORE INC | 68.76 | | 68.76 | | |
| 79200 | 299 | Miscellaneous | GIFTARIA | 106.00 | | 106.00 | | |
| 79200 | 299 | Miscellaneous | INGLIS BROADWAY FLORIS | 196.01 | | 196.01 | | |
| 79200 | 299 | Miscellaneous | INTERNATIONAL CORPORAT | 407.54 | | 407.54 | | |
| 79200 | 299 | Miscellaneous | MAYFIELD FLORIST | 132.69 | | 132.69 | | |
| 79200 | 299 | Miscellaneous | MICHAELS #5206 | 414.28 | | 414.28 | | |
| 79200 | 299 | Miscellaneous | PARK PLACE | 148.00 | | 148.00 | | |
| 79200 | 299 | Miscellaneous | PARKS/REC RANDOLPH PRO | 529.39 | | 529.39 | | |
| 79200 | 299 | Miscellaneous | PARTY AMERICA | 94.34 | | 94.34 | | |
| 79200 | 299 | Miscellaneous | PAYPAL *BOSTIC WS | 565.49 | | 565.49 | | |
| 79200 | 299 | Miscellaneous | PROFLOWERS.COM | 52.40 | | 52.40 | | |
| 79200 | 299 | Miscellaneous | reclass SPRGPAY PA3231206 | 1,368.95 | | 1,368.95 | | |
| 79200 | 299 | Miscellaneous | SAFEWAY STORE00015214 | 52.51 | | 52.51 | | |
| 79200 | 299 | Miscellaneous | SAFEWAY STORE 00019869 | 16.20 | | 16.20 | | |
| 79200 | 299 | Miscellaneous | SALLIE MAE - SLM GWU A | 60.00 | | 60.00 | | |
| 79200 | 299 | Miscellaneous | TIERRA LINDA DESIGNS I | 387.45 | | 387.45 | | |
| 79200 | 299 | Miscellaneous | TLF*CASAS ADOBES FLOWE | 169.24 | | 169.24 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79200 | 299 | Miscellaneous | TLF*FLORAL ORIGINALS B | 113.35 | | 113.35 | | |
| 79200 | 299 | Miscellaneous | TLF*INGLIS BROADWAY FL | 868.48 | | 868.48 | | |
| 79200 | 299 | Miscellaneous | TLF*MAYFIELD FLST | 321.58 | | 321.58 | | |
| 79200 | 299 | Miscellaneous | TLF*TELEFLORA.COM | 73.93 | | 73.93 | | |
| 79200 | 299 | Miscellaneous | TLF*THE BALLOON FACTOR | 45.25 | | 45.25 | | |
| 79200 | 299 | Miscellaneous | USGOVT PRINTING OFC 3- | 62.00 | | 62.00 | | |
| 79200 | 299 | Miscellaneous | USGPO/PUBLICATIONS/ND- | 70.50 | | 70.50 | | |
| 79200 | 299 | Miscellaneous | V SATTUI WINERY RETAIL | 61.36 | | 61.36 | | |
| 79200 | 299 | Miscellaneous | VILLA FELIZ FLOWERS | 134.91 | | 134.91 | | |
| 79200 | 299 | Miscellaneous | WALGREEN 00070Q39 | 37.19 | | 37.19 | | |
| 79200 | 299 | Miscellaneous | WAL-MART #1291 | 34.49 | | 34.49 | | |
| 51500 | 206 | Office Supplies | ALBERTSONS #964 S9H | 11.97 | | 11.97 | | |
| 51500 | 206 | Office Supplies | BAGGINS STORE #8 | 43.78 | | 43.78 | | |
| 51500 | 206 | Office Supplies | BRUEGGER'S BAGELS -Q51 | 17.64 | | 17.64 | | |
| 51500 | 206 | Office Supplies | DISCOUNT COFFEE COM | 388.56 | | 388.56 | | |
| 51500 | 206 | Office Supplies | DIZZY GS RESTAURANT | 37.00 | | 37.00 | | |
| 51500 | 206 | Office Supplies | FRYS-FOOD-DRG #020 SXN | 2.99 | | 2.99 | | |
| 51500 | 206 | Office Supplies | FRYS-FOOD-DRG #033 SXN | 50.26 | | 50.26 | | |
| 51500 | 206 | Office Supplies | FRYS-FOOD-DRG #042 SXN | 19.08 | | 19.08 | | |
| 51500 | 206 | Office Supplies | FRYS-FOOD-DRG #058 SXN | 129.02 | | 129.02 | | |
| 51500 | 206 | Office Supplies | HALLMARK CREATIONS #56 | 41.48 | | 41.48 | | |
| 51500 | 206 | Office Supplies | HERITAGE PRODUCTS INC | 550.88 | | 550.88 | | |
| 51500 | 206 | Office Supplies | KMART 00049SZI | 45.40 | | 45.40 | | |
| 51500 | 206 | Office Supplies | PARTY AMERICA #1404 | 71.76 | | 71.76 | | |
| 51500 | 206 | Office Supplies | SAFEWAY STORE00018747 | 35.80 | | 35.80 | | |
| 51500 | 206 | Office Supplies | SAFEWAY STORE00018SC9 | 77.35 | | 77.35 | | |
| 51500 | 206 | Office Supplies | SAFEWAY STORE 00019893 | 28.00 | | 28.00 | | |
| 51500 | 206 | Office Supplies | TARGET 00014399 | 97.27 | | 97.27 | | |
| 51500 | 206 | Office Supplies | WAL MART | 102.18 | | 102.18 | | |
| 51500 | 206 | Office Supplies | WALGREEN 00051Q39 | 3.98 | | 3.98 | | |
| 51500 | 206 | Office Supplies | WALGREEN 00067Q39 | 10.77 | | 10.77 | | |
| 51500 | 206 | Office Supplies | WAL-MART #1291 | 8.33 | | 8.33 | | |
| 51500 | 206 | Office Supplies | WAL-MART #1612 SE2 | 2.56 | | 2.56 | | |
| 51500 | 206 | Office Supplies | WM SUPERCENTER SE2 | 105.84 | | 105.84 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | AJ S 122 | 256.93 | | 256.93 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | ALBERTSONS #972 | 9.99 | | 9.99 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | BAGGINS STORE #10 | 25.63 | | 25.63 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | BASKIN ROBBINS | 28.59 | | 28.59 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | BEER BOTTOM'S BISTRO | 54.94 | | 54.94 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | BENNIGANS | 40.20 | | 40.20 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | BEYOND BREAD-CAMPB | 29.73 | | 29.73 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | BIG APPLE GOODYEAR | 12.41 | | 12.41 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | BISON WITCHES BAR & DE | 32.57 | | 32.57 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 52100 | 160 | Outside Serv - Meals & Enter | CAFE JASPER | 24.32 | | 24.32 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | CANOA HILLS GOLF COURS | 102.92 | | 102.92 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | CANOA HILLS GOLF F/B | 10.00 | | 10.00 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | CHILI'S GRI56300005637 | 95.16 | | 95.16 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | CHIPOTLE #0085 Q82 | 15.67 | | 15.67 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | CLAIM JUMPER #35 | 141.48 | | 141.48 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | COACHES CORNER | 26.17 | | 26.17 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | DENNY'S #6614 Q67 | 8.05 | | 8.05 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | DENNY'S #6716 Q67 | 7.15 | | 7.15 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | DESERT DIAMOND CASINO | 243.70 | | 243.70 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | DONUT WHEEL | 9.80 | | 9.80 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | EL CHARO | 31.48 | | 31.48 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | EL CHARRO-ORIGINAL | 95.09 | | 95.09 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | EL PASO BAR-B-QUE 555 | 233.26 | | 233.26 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | EL SABROSO | 90.60 | | 90.60 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | ENOTECA PIZZARIA WINE | 31.53 | | 31.53 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | FAMOUS SAMS #28 | 43.95 | | 43.95 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | HIFALUTIN | 25.99 | | 25.99 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | JB'S RESTAURANT 11 | 41.46 | | 41.46 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | JERRY BOB'S | 8.48 | | 8.48 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | LA PARILLA SUIZA | 67.68 | | 67.68 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | LA PARRILLA SUIZA #3 | 58.76 | | 58.76 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | LAS CAZUELITAS DE TUCS | 48.45 | | 48.45 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | LUKES ITALIAN BEEF | 17.48 | | 17.48 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | MACARONI GR16300001636 | 31.24 | | 31.24 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | MARISCOS CHIHUAHUA | 67.10 | | 67.10 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | MICHAS | 87.42 | | 87.42 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | OMNI HOTELS F/B | 52.44 | | 52.44 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | OREGANO S | 47.46 | | 47.46 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | P.F. CHANG'S #8000 | 43.05 | | 43.05 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | PARRILLA DEL REY | 23.26 | | 23.26 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | RED LOBSTER US00008698 | 43.47 | | 43.47 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | SAFEWAY STORE00015SC9 | 21.98 | | 21.98 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | SAFEWAY STORE 00019877 | 22.99 | | 22.99 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | SAM HUGHES PLACE | 144.75 | | 144.75 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | SILVER SADDLE STEAKHOU | 60.51 | | 60.51 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | SPROUTS FARMERS MARSPR | 6.88 | | 6.88 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | TEXAS ROADHOUSE #2204 | 35.21 | | 35.21 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | THE GALLERY RESTAURANT | 28.86 | | 28.86 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | THE GOOD EGG WILLIAMS | 72.15 | | 72.15 | | |
| 52100 | 160 | Outside Serv - Meals & Enter | TUCSON GOLF/CONF GOLF | 549.12 | | 549.12 | | |
| 55020 | 354 | Software Licenses | ASPEN | 150.00 | | 150.00 | | |
| 55020 | 354 | Software Licenses | BEER BOTTOM'S BISTRO | 48.44 | | 48.44 | | |
| 55020 | 354 | Software Licenses | CHILI'S GRI56300005637 | 55.94 | | 55.94 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 55020 | 354 | Software Licenses | CHUMBO.COM | 70.99 | | 70.99 | | |
| 79200 | 205 | Subs & Ref Materials | WWW.COSTCO.COM | 53.80 | | 53.80 | | |
| 79200 | 205 | Subs & Ref Materials | | 243.17 | | 243.17 | COSTCO WHOLESALE | 021606 835964 |
| 55000 | 403 | Transportation Usage | | 2,310.41 | | 2,310.41 | | |
| 79010 | 272 | Travel | 9210150201BT | 2,259.89 | | 2,259.89 | | |
| 79010 | 272 | Travel | 9210150350BT | 6,227.93 | | 6,227.93 | | |
| 79010 | 272 | Travel | 9210250151BT | 4,905.23 | | 4,905.23 | | |
| 79010 | 272 | Travel | 9210250151BT E-0101 | 2,875.19 | | 2,875.19 | | |
| 79010 | 272 | Travel | 9210250201BT | 3,301.77 | | 3,301.77 | | |
| 79010 | 272 | Travel | 9210250350BT | 3,207.64 | | 3,207.64 | | |
| 79010 | 272 | Travel | 9210400840BT | 3,749.14 | | 3,749.14 | | |
| 79010 | 272 | Travel | 9210400840BT 4026 | 2,746.34 | | 2,746.34 | | |
| 79010 | 272 | Travel | ALL RESORT EXPRESS | 2,000.00 | | 2,000.00 | | |
| 79010 | 272 | Travel | COURTYARD BY MARRIOTT- | 2,669.55 | | 2,669.55 | | |
| 79010 | 272 | Travel | EXPEDIA*TRAVEL | 4,675.55 | | 4,675.55 | | |
| 79010 | 272 | Travel | HERTZ RENT-A-CAR | 2,361.14 | | 2,361.14 | | |
| 79010 | 272 | Travel | HILTON HOTELS | 3,878.46 | | 3,878.46 | | |
| 79010 | 272 | Travel | HILTON HOTELS LINC CTR | 2,969.14 | | 2,969.14 | | |
| 79010 | 272 | Travel | HYATT HOTELS SAN FRANC | 2,544.70 | | 2,544.70 | | |
| 79010 | 272 | Travel | HYATT REGENCY WASHINGT | 2,706.81 | | 2,706.81 | | |
| 79010 | 272 | Travel | MARRIOTT 337E4 DESERT | 3,248.14 | | 3,248.14 | | |
| 79010 | 272 | Travel | MARRIOTT HOTELS UNIVER | 2,261.98 | | 2,261.98 | | |
| 79010 | 272 | Travel | OMNI HOTELS INTERLOCKE | 3,197.22 | | 3,197.22 | | |
| 79010 | 272 | Travel | SOIREE PRODUCTIONS WHI | 3,043.17 | | 3,043.17 | | |
| 79010 | 272 | Travel | THOROUGHBRED PAINT & B | 2,439.84 | | 2,439.84 | | |
| 79010 | 281 | Travel - Discretionary | CLAIM JUMPER #35 | 86.80 | | 86.80 | | |
| 79010 | 281 | Travel - Discretionary | | 259.30 | | 259.30 | | |
| 79010 | 274 | Travel - Lodging | THE BENJAMIN | 3,916.04 | | 3,916.04 | | |
| 79010 | 275 | Travel - Meals & Enter | 1410 BIER MARKET RESTA | 16.65 | | 16.65 | | |
| 79010 | 275 | Travel - Meals & Enter | 4TH AVE VINTAGE HIDEAW | 46.25 | | 46.25 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150190ET | 28.35 | | 28.35 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150201ET | 535.43 | | 535.43 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150201ET 4026 | 90.40 | | 90.40 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150350ET | 1,434.71 | | 1,434.71 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150350ET E-0044 | 78.16 | | 78.16 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150360ET | 90.31 | | 90.31 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150360ET E-0295 | 37.07 | | 37.07 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150360ET E-0353 | 46.55 | | 46.55 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210150360ET E-0475 | 57.85 | | 57.85 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210250151ET | 331.00 | | 331.00 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210250151ET E-0101 | 433.53 | | 433.53 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210250190ET | 548.60 | | 548.60 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210250201ET | 540.83 | | 540.83 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | 9210250340ET | 652.80 | | 652.80 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210250341ET | 38.19 | | 38.19 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210250341ET | | 38.19 | (38.19) | | |
| 79010 | 275 | Travel - Meals & Enter | 9210250350ET | 561.61 | | 561.61 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210250360ET | 552.99 | | 552.99 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210400360ET | 240.00 | | 240.00 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210400840ET | 1,200.00 | | 1,200.00 | | |
| 79010 | 275 | Travel - Meals & Enter | 9210400840ET 4026 | 312.08 | | 312.08 | | |
| 79010 | 275 | Travel - Meals & Enter | AJ S 122 SYM | 119.60 | | 119.60 | | |
| 79010 | 275 | Travel - Meals & Enter | AKIKO'S SUSHI BAR | 20.76 | | 20.76 | | |
| 79010 | 275 | Travel - Meals & Enter | ALADDIN-SPICE MARKET B | 29.93 | | 29.93 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #961 S9H | 17.16 | | 17.16 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #964 | 84.56 | | 84.56 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #972 | 28.08 | | 28.08 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #972 S9H | 14.98 | | 14.98 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBUQUERQUE INT'L AIRP | 21.25 | | 21.25 | | |
| 79010 | 275 | Travel - Meals & Enter | ALEJANDRO'S CAFE | 160.25 | | 160.25 | | |
| 79010 | 275 | Travel - Meals & Enter | ALEXIS | 42.50 | | 42.50 | | |
| 79010 | 275 | Travel - Meals & Enter | AMERICA | 26.57 | | 26.57 | | |
| 79010 | 275 | Travel - Meals & Enter | APPLEBEE'S #17NEIGHBOR | 19.83 | | 19.83 | | |
| 79010 | 275 | Travel - Meals & Enter | APPLEBEES #511 | 163.30 | | 163.30 | | |
| 79010 | 275 | Travel - Meals & Enter | APPLEBEE'S #602 | 184.34 | | 184.34 | | |
| 79010 | 275 | Travel - Meals & Enter | APPLEBEE'S #605 | 10.47 | | 10.47 | | |
| 79010 | 275 | Travel - Meals & Enter | APPLEBEE'S MEN00164087 | 52.46 | | 52.46 | | |
| 79010 | 275 | Travel - Meals & Enter | ARBY'S #1180 00011Q52 | 9.74 | | 9.74 | | |
| 79010 | 275 | Travel - Meals & Enter | ARBY'S #7019 Q52 | 11.92 | | 11.92 | | |
| 79010 | 275 | Travel - Meals & Enter | ASIA GARDEN REST | 22.32 | | 22.32 | | |
| 79010 | 275 | Travel - Meals & Enter | ASPECT COMM STORE Q79 | 139.37 | | 139.37 | | |
| 79010 | 275 | Travel - Meals & Enter | ASU-PANDINI'S 30012Q20 | 6.90 | | 6.90 | | |
| 79010 | 275 | Travel - Meals & Enter | AU BON PAIN | 7.07 | | 7.07 | | |
| 79010 | 275 | Travel - Meals & Enter | AU BON PAIN #4 | 18.19 | | 18.19 | | |
| 79010 | 275 | Travel - Meals & Enter | AU BON PAINS | 17.76 | | 17.76 | | |
| 79010 | 275 | Travel - Meals & Enter | AUNT CHILADAS | 28.67 | | 28.67 | | |
| 79010 | 275 | Travel - Meals & Enter | AUNTIE ANNE'S PRETZQ29 | 1.72 | | 1.72 | | |
| 79010 | 275 | Travel - Meals & Enter | AVENUE GRILL | 100.00 | | 100.00 | | |
| 79010 | 275 | Travel - Meals & Enter | AZ MX COMMISSION | 500.00 | | 500.00 | | |
| 79010 | 275 | Travel - Meals & Enter | BACI RESTAURANT | 35.25 | | 35.25 | | |
| 79010 | 275 | Travel - Meals & Enter | BACK YARD BURGERS #032 | 6.98 | | 6.98 | | |
| 79010 | 275 | Travel - Meals & Enter | BAGGINS STORE #10 | 1,159.07 | | 1,159.07 | | |
| 79010 | 275 | Travel - Meals & Enter | BAGGINS STORE #8 | 1,248.69 | | 1,248.69 | | |
| 79010 | 275 | Travel - Meals & Enter | BAGGINS STORE #9 | 8.43 | | 8.43 | | |
| 79010 | 275 | Travel - Meals & Enter | BAHAMA BREEZE 00030114 | 39.33 | | 39.33 | | |
| 79010 | 275 | Travel - Meals & Enter | BAMBOO TERRACE RESTAUR | 121.88 | | 121.88 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | BAMBOO TUCSON | 648.68 | | 648.68 | | |
| 79010 | 275 | Travel - Meals & Enter | BARNES & NOBLE #2060 | 4.28 | | 4.28 | | |
| 79010 | 275 | Travel - Meals & Enter | BARRIO | 528.41 | | 528.41 | | |
| 79010 | 275 | Travel - Meals & Enter | BASHAS #160 | 19.16 | | 19.16 | | |
| 79010 | 275 | Travel - Meals & Enter | BASHAS #86 SYW | 55.86 | | 55.86 | | |
| 79010 | 275 | Travel - Meals & Enter | BCG@LITTLE FIGS | 23.78 | | 23.78 | | |
| 79010 | 275 | Travel - Meals & Enter | BEAVER STREET BREW | 82.70 | | 82.70 | | |
| 79010 | 275 | Travel - Meals & Enter | BEER BOTTOM'S BISTRO | 510.58 | | 510.58 | | |
| 79010 | 275 | Travel - Meals & Enter | BELLAGIO HOTEL & CASIN | 154.91 | | 154.91 | | |
| 79010 | 275 | Travel - Meals & Enter | BENIHANA #OR | 87.16 | | 87.16 | | |
| 79010 | 275 | Travel - Meals & Enter | BENNIGANS | 28.99 | | 28.99 | | |
| 79010 | 275 | Travel - Meals & Enter | BEST WESTERN CENTRAL P | 39.05 | | 39.05 | | |
| 79010 | 275 | Travel - Meals & Enter | BEYOND BREAD | 24.26 | | 24.26 | | |
| 79010 | 275 | Travel - Meals & Enter | BEYOND BREAD-CAMPB | 14.59 | | 14.59 | | |
| 79010 | 275 | Travel - Meals & Enter | BIANCHIS ITALIAN | 71.95 | | 71.95 | | |
| 79010 | 275 | Travel - Meals & Enter | BIG CITY BBQ & GRILL | 12.79 | | 12.79 | | |
| 79010 | 275 | Travel - Meals & Enter | BIGFOOT BARBECUE | 32.43 | | 32.43 | | |
| 79010 | 275 | Travel - Meals & Enter | BLACK JACK PIZZA ST MA | 44.70 | | 44.70 | | |
| 79010 | 275 | Travel - Meals & Enter | BOB DOBBS | 35.80 | | 35.80 | | |
| 79010 | 275 | Travel - Meals & Enter | BOB THE FISH | 20.01 | | 20.01 | | |
| 79010 | 275 | Travel - Meals & Enter | BON APPETIT@ 51153Q99 | 19.36 | | 19.36 | | |
| 79010 | 275 | Travel - Meals & Enter | BOOGA REDS | 72.11 | | 72.11 | | |
| 79010 | 275 | Travel - Meals & Enter | BOSTON MARKET #0444Q98 | 38.90 | | 38.90 | | |
| 79010 | 275 | Travel - Meals & Enter | BOWLINS PICACHO PEAK P | 3.38 | | 3.38 | | |
| 79010 | 275 | Travel - Meals & Enter | BROOKLYNS | 210.17 | | 210.17 | | |
| 79010 | 275 | Travel - Meals & Enter | BRUEGGERS BAGEL BAKERY | 344.15 | | 344.15 | | |
| 79010 | 275 | Travel - Meals & Enter | BRUEGGER'S BAGELS -Q51 | 175.41 | | 175.41 | | |
| 79010 | 275 | Travel - Meals & Enter | BRUEGGER'S BAGELS -Q55 | 11.69 | | 11.69 | | |
| 79010 | 275 | Travel - Meals & Enter | BRUEGGERS BAGELS#29-02 | 31.11 | | 31.11 | | |
| 79010 | 275 | Travel - Meals & Enter | BUBBA GUMP REST #344 | 65.00 | | 65.00 | | |
| 79010 | 275 | Travel - Meals & Enter | BUDDY S GRILL | 31.00 | | 31.00 | | |
| 79010 | 275 | Travel - Meals & Enter | BUDDY'S | 38.00 | | 38.00 | | |
| 79010 | 275 | Travel - Meals & Enter | BUN HUGGERS WEST | 20.64 | | 20.64 | | |
| 79010 | 275 | Travel - Meals & Enter | BURGER KING #3109 Q07 | 6.25 | | 6.25 | | |
| 79010 | 275 | Travel - Meals & Enter | BURGER KING #9759 Q07 | 4.61 | | 4.61 | | |
| 79010 | 275 | Travel - Meals & Enter | BUSTER S RESTAURANT | 50.84 | | 50.84 | | |
| 79010 | 275 | Travel - Meals & Enter | BUSTERS | 49.06 | | 49.06 | | |
| 79010 | 275 | Travel - Meals & Enter | BUSY B S BAKERY | 33.07 | | 33.07 | | |
| 79010 | 275 | Travel - Meals & Enter | BUZZARDS-BOTTLESCREW B | 28.17 | | 28.17 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFE A LA CART | 1,479.48 | | 1,479.48 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFE METRO - CM - | 33.55 | | 33.55 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFE METRO - CM - QAE | 10.28 | | 10.28 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFE POCA COSA | 560.68 | | 560.68 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | CAFE TIRAMISU | 26.70 | | 26.70 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFETERIA | 33.02 | | 33.02 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFFE MILANO LLC | 361.26 | | 361.26 | | |
| 79010 | 275 | Travel - Meals & Enter | CALIFORNIA PIZZA 150 | 21.59 | | 21.59 | | |
| 79010 | 275 | Travel - Meals & Enter | CANTINA GRILL B CONCOU | 33.00 | | 33.00 | | |
| 79010 | 275 | Travel - Meals & Enter | CAPITAL GRILLE 802 | 75.58 | | 75.58 | | |
| 79010 | 275 | Travel - Meals & Enter | CAPPELLOS ITALIAN | 77.55 | | 77.55 | | |
| 79010 | 275 | Travel - Meals & Enter | CASA DEL FOOD SERVIQ44 | 9.50 | | 9.50 | | |
| 79010 | 275 | Travel - Meals & Enter | CASA RIO MEXICAN FOODS | 13.50 | | 13.50 | | |
| 79010 | 275 | Travel - Meals & Enter | CASA SANCHEZ MOM'S MEX | 36.05 | | 36.05 | | |
| 79010 | 275 | Travel - Meals & Enter | CATTLEMEN'S #9 | 42.01 | | 42.01 | | |
| 79010 | 275 | Travel - Meals & Enter | CATTLETOWN STEAKHOUSE | 36.10 | | 36.10 | | |
| 79010 | 275 | Travel - Meals & Enter | CB & POTTS #11 | 21.09 | | 21.09 | | |
| 79010 | 275 | Travel - Meals & Enter | CHACO'S CAFE | 143.52 | | 143.52 | | |
| 79010 | 275 | Travel - Meals & Enter | CHAFFINS FAMILY RESTAU | 21.22 | | 21.22 | | |
| 79010 | 275 | Travel - Meals & Enter | CHALO S CASA DE REYNOS | 30.24 | | 30.24 | | |
| 79010 | 275 | Travel - Meals & Enter | CHARIOT PIZZA | 481.09 | | 481.09 | | |
| 79010 | 275 | Travel - Meals & Enter | CHARLESTON S CHANDLER | 13.25 | | 13.25 | | |
| 79010 | 275 | Travel - Meals & Enter | CHARLIECLARK'SSTEAKHOU | 216.81 | | 216.81 | | |
| 79010 | 275 | Travel - Meals & Enter | CHARLIE'S GRILLED SUBS | 14.99 | | 14.99 | | |
| 79010 | 275 | Travel - Meals & Enter | CHAYA BRASSERIE (SF) | 122.42 | | 122.42 | | |
| 79010 | 275 | Travel - Meals & Enter | CHEESECAKE DENVER | 184.45 | | 184.45 | | |
| 79010 | 275 | Travel - Meals & Enter | CHEESECAKE LAS VEGAS | 38.50 | | 38.50 | | |
| 79010 | 275 | Travel - Meals & Enter | CHEESECAKE NO SCOTTSDA | 22.59 | | 22.59 | | |
| 79010 | 275 | Travel - Meals & Enter | CHEESECAKE PHOENIX | 27.46 | | 27.46 | | |
| 79010 | 275 | Travel - Meals & Enter | CHEESECAKE STONEBRIAR | 56.52 | | 56.52 | | |
| 79010 | 275 | Travel - Meals & Enter | CHESAPEAKE BAGEL &BAKE | 1.68 | | 1.68 | | |
| 79010 | 275 | Travel - Meals & Enter | CHEVRON 0208629 Q61 | 3.66 | | 3.66 | | |
| 79010 | 275 | Travel - Meals & Enter | CHILI'S GRI04600010462 | 166.16 | | 166.16 | | |
| 79010 | 275 | Travel - Meals & Enter | CHILI'S GRI09500010959 | 45.79 | | 45.79 | | |
| 79010 | 275 | Travel - Meals & Enter | CHILI'S GRI38100003814 | 21.32 | | 21.32 | | |
| 79010 | 275 | Travel - Meals & Enter | CHILI'S GRI41600004168 | 34.79 | | 34.79 | | |
| 79010 | 275 | Travel - Meals & Enter | CHILI'S GRI42700004275 | 92.58 | | 92.58 | | |
| 79010 | 275 | Travel - Meals & Enter | CHILI'S GRI56300005637 | 461.32 | | 461.32 | | |
| 79010 | 275 | Travel - Meals & Enter | CHINA GARDEN | 30.86 | | 30.86 | | |
| 79010 | 275 | Travel - Meals & Enter | CHINATOWN BUFFET | 31.91 | | 31.91 | | |
| 79010 | 275 | Travel - Meals & Enter | CHIPOTLE #0742 Q26 | 16.11 | | 16.11 | | |
| 79010 | 275 | Travel - Meals & Enter | CHOPSTIX | 113.15 | | 113.15 | | |
| 79010 | 275 | Travel - Meals & Enter | CHRIS' CAFE | 50.59 | | 50.59 | | |
| 79010 | 275 | Travel - Meals & Enter | CHRISTMASTREE REST | 211.67 | | 211.67 | | |
| 79010 | 275 | Travel - Meals & Enter | CHU S MONGOLIAN BARBEQ | 35.20 | | 35.20 | | |
| 79010 | 275 | Travel - Meals & Enter | CHUCK WAGON STEAKH | 90.05 | | 90.05 | | |
| 79010 | 275 | Travel - Meals & Enter | CINNABON | 31.97 | | 31.97 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | CINNABON #177 Q66 | 1.90 | | 1.90 | | |
| 79010 | 275 | Travel - Meals & Enter | CIRCLE K 00423 Q04 | 4.56 | | 4.56 | | |
| 79010 | 275 | Travel - Meals & Enter | CIRCLE K 01383 Q04 | 8.72 | | 8.72 | | |
| 79010 | 275 | Travel - Meals & Enter | CLAIM JUMPER #35 | 3,558.78 | | 3,558.78 | | |
| 79010 | 275 | Travel - Meals & Enter | CLIFF CASTLE CASINO | 22.65 | | 22.65 | | |
| 79010 | 275 | Travel - Meals & Enter | COCOS BAKERY RESTAURAN | 20.03 | | 20.03 | | |
| 79010 | 275 | Travel - Meals & Enter | CODYS BEEF AND BEANS | 32.86 | | 32.86 | | |
| 79010 | 275 | Travel - Meals & Enter | COFFEE PLANTATION | 2.30 | | 2.30 | | |
| 79010 | 275 | Travel - Meals & Enter | COFFEE POT RESTAURANT | 16.89 | | 16.89 | | |
| 79010 | 275 | Travel - Meals & Enter | COOKIES BY DESIGN OF T | 80.85 | | 80.85 | | |
| 79010 | 275 | Travel - Meals & Enter | COPPER SQUARE GRILL | 25.38 | | 25.38 | | |
| 79010 | 275 | Travel - Meals & Enter | CORKY'S BAR-B-Q | 16.66 | | 16.66 | | |
| 79010 | 275 | Travel - Meals & Enter | COSI # 48 Q83 | 4.38 | | 4.38 | | |
| 79010 | 275 | Travel - Meals & Enter | COURTYARD BY MARRIOTT- | 11.85 | | 11.85 | | |
| 79010 | 275 | Travel - Meals & Enter | COYOTE CAFE & BISTRO A | 16.95 | | 16.95 | | |
| 79010 | 275 | Travel - Meals & Enter | COYOTE CREEK STEAK HOU | 291.64 | | 291.64 | | |
| 79010 | 275 | Travel - Meals & Enter | CRACKER BARREL #344 | 54.44 | | 54.44 | | |
| 79010 | 275 | Travel - Meals & Enter | CRACKER BARREL #388 | 20.00 | | 20.00 | | |
| 79010 | 275 | Travel - Meals & Enter | CRACKER BARREL #416 | 31.64 | | 31.64 | | |
| 79010 | 275 | Travel - Meals & Enter | CRAVINGS RESTAURANT | 190.00 | | 190.00 | | |
| 79010 | 275 | Travel - Meals & Enter | CREWS OF CALIFORNI | 1.99 | | 1.99 | | |
| 79010 | 275 | Travel - Meals & Enter | CROSSCORNER | 28.28 | | 28.28 | | |
| 79010 | 275 | Travel - Meals & Enter | CROSSROADS RESTAURAN | 74.00 | | 74.00 | | |
| 79010 | 275 | Travel - Meals & Enter | CUVEE WORLD BISTRO | 536.94 | | 536.94 | | |
| 79010 | 275 | Travel - Meals & Enter | DAGLIOS CHEESESTEAKS & | 59.45 | | 59.45 | | |
| 79010 | 275 | Travel - Meals & Enter | DAISY MAE'S STRONGHOLD | 33.15 | | 33.15 | | |
| 79010 | 275 | Travel - Meals & Enter | DAVE & BUSTER'S #24 | 148.22 | | 148.22 | | |
| 79010 | 275 | Travel - Meals & Enter | DAVE & BUSTER'S #29 | 38.33 | | 38.33 | | |
| 79010 | 275 | Travel - Meals & Enter | DCA MARKETS | 4.88 | | 4.88 | | |
| 79010 | 275 | Travel - Meals & Enter | DE ANZA RESTAURANT & C | 78.75 | | 78.75 | | |
| 79010 | 275 | Travel - Meals & Enter | DEBS CONEY CAFE | 26.49 | | 26.49 | | |
| 79010 | 275 | Travel - Meals & Enter | DELECTABLES RESTAURANT | 1,391.51 | | 1,391.51 | | |
| 79010 | 275 | Travel - Meals & Enter | DENNY'S 00867432 | 243.08 | | 243.08 | | |
| 79010 | 275 | Travel - Meals & Enter | DENNY'S #6534 Q67 | 20.91 | | 20.91 | | |
| 79010 | 275 | Travel - Meals & Enter | DENNY'S #6614 Q67 | 41.02 | | 41.02 | | |
| 79010 | 275 | Travel - Meals & Enter | DENNY'S #6716 | 21.06 | | 21.06 | | |
| 79010 | 275 | Travel - Meals & Enter | DENNY'S #7297 Q67 | 50.00 | | 50.00 | | |
| 79010 | 275 | Travel - Meals & Enter | DENNY'S #7415 Q67 | 14.76 | | 14.76 | | |
| 79010 | 275 | Travel - Meals & Enter | DENNY'S INC Q67 | 86.76 | | 86.76 | | |
| 79010 | 275 | Travel - Meals & Enter | DESERT DIAMOND CASINO | 192.80 | | 192.80 | | |
| 79010 | 275 | Travel - Meals & Enter | DIAMONDS CHINESE RESTA | 38.75 | | 38.75 | | |
| 79010 | 275 | Travel - Meals & Enter | DINING ARTISTS PT | 138.16 | | 138.16 | | |
| 79010 | 275 | Travel - Meals & Enter | DISNEY HILTON RESTRNT | 15.99 | | 15.99 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | DIZZY GS RESTAURANT | 34.39 | | 34.39 | | |
| 79010 | 275 | Travel - Meals & Enter | DOMINOES PIZZA #7634 | 206.83 | | 206.83 | | |
| 79010 | 275 | Travel - Meals & Enter | DON ALEJANDROS TEXAN G | 28.00 | | 28.00 | | |
| 79010 | 275 | Travel - Meals & Enter | DONOVANS STEAK AND | 225.00 | | 225.00 | | |
| 79010 | 275 | Travel - Meals & Enter | DOUBE D'S SPORTS GRILL | 48.85 | | 48.85 | | |
| 79010 | 275 | Travel - Meals & Enter | DOUBLETREE HOTEL F&B | 85.54 | | 85.54 | | |
| 79010 | 275 | Travel - Meals & Enter | DRAGON VILLAGE RES | 43.10 | | 43.10 | | |
| 79010 | 275 | Travel - Meals & Enter | DUCK & DECANTER | 187.53 | | 187.53 | | |
| 79010 | 275 | Travel - Meals & Enter | DUNKIN DONUTS | 22.36 | | 22.36 | | |
| 79010 | 275 | Travel - Meals & Enter | DUNKIN DONUTS #306705 | 5.89 | | 5.89 | | |
| 79010 | 275 | Travel - Meals & Enter | DURANTS | 35.87 | | 35.87 | | |
| 79010 | 275 | Travel - Meals & Enter | EAGLEWOOD RESORT AND S | 3.20 | | 3.20 | | |
| 79010 | 275 | Travel - Meals & Enter | EAST SIDE MARIOS | 9.03 | | 9.03 | | |
| 79010 | 275 | Travel - Meals & Enter | ECLECTIC CAFE | 31.67 | | 31.67 | | |
| 79010 | 275 | Travel - Meals & Enter | EEGEE S | 427.38 | | 427.38 | | |
| 79010 | 275 | Travel - Meals & Enter | EINSTEIN BROS #3064 | 78.02 | | 78.02 | | |
| 79010 | 275 | Travel - Meals & Enter | EL CHARO | 204.00 | | 204.00 | | |
| 79010 | 275 | Travel - Meals & Enter | EL CHARRO-ORIGINAL | 293.81 | | 293.81 | | |
| 79010 | 275 | Travel - Meals & Enter | EL CORRAL RESTAURANT | 3.75 | | 3.75 | | |
| 79010 | 275 | Travel - Meals & Enter | EL GUERO CANELO | 92.18 | | 92.18 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MINUTO CAFE | 498.03 | | 498.03 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MOLINITO | 170.05 | | 170.05 | | |
| 79010 | 275 | Travel - Meals & Enter | EL PARADOR | 23.10 | | 23.10 | | |
| 79010 | 275 | Travel - Meals & Enter | EL PASO BAR B QUE | 260.58 | | 260.58 | | |
| 79010 | 275 | Travel - Meals & Enter | EL PASO BAR-B-QUE 555 | 1,249.71 | | 1,249.71 | | |
| 79010 | 275 | Travel - Meals & Enter | EL POLLO #3567 | 8.41 | | 8.41 | | |
| 79010 | 275 | Travel - Meals & Enter | EL SABROSO | 99.14 | | 99.14 | | |
| 79010 | 275 | Travel - Meals & Enter | EL SAGUARITO | 493.35 | | 493.35 | | |
| 79010 | 275 | Travel - Meals & Enter | EL SUR RESTAURANT | 47.67 | | 47.67 | | |
| 79010 | 275 | Travel - Meals & Enter | EL TACO TOTE #7 | 48.15 | | 48.15 | | |
| 79010 | 275 | Travel - Meals & Enter | EL TORERO | 99.53 | | 99.53 | | |
| 79010 | 275 | Travel - Meals & Enter | ELEPHANT BAR # 228 | 31.24 | | 31.24 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 102.00 | | 102.00 | | |
| 79010 | 275 | Travel - Meals & Enter | EMERILS NO FISH HOUSE | 29.63 | | 29.63 | | |
| 79010 | 275 | Travel - Meals & Enter | ENOTECA PIZZARIA WINE | 1,657.53 | | 1,657.53 | | |
| 79010 | 275 | Travel - Meals & Enter | F15751 MCDONALD'S Q17 | 6.27 | | 6.27 | | |
| 79010 | 275 | Travel - Meals & Enter | FAMOUS DAVE'S BBQ | 74.49 | | 74.49 | | |
| 79010 | 275 | Travel - Meals & Enter | FAMOUS SAMS #17 | 28.00 | | 28.00 | | |
| 79010 | 275 | Travel - Meals & Enter | FAMOUS SAMS #28 | 157.96 | | 157.96 | | |
| 79010 | 275 | Travel - Meals & Enter | FIESTA MEXICANA #7 | 44.16 | | 44.16 | | |
| 79010 | 275 | Travel - Meals & Enter | FINEMONDO | 1,208.16 | | 1,208.16 | | |
| 79010 | 275 | Travel - Meals & Enter | FIRST WATCH #4 | 11.27 | | 11.27 | | |
| 79010 | 275 | Travel - Meals & Enter | FISH MARKET SD | 26.05 | | 26.05 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | FISH MARKET SM | 39.00 | | 39.00 | | |
| 79010 | 275 | Travel - Meals & Enter | FLATIRON CAFE | 53.22 | | 53.22 | | |
| 79010 | 275 | Travel - Meals & Enter | FONTINA RISTORANTE | 27.73 | | 27.73 | | |
| 79010 | 275 | Travel - Meals & Enter | FOOD CITY #147 ST3 | 205.74 | | 205.74 | | |
| 79010 | 275 | Travel - Meals & Enter | FOOD CITY #77 SYW | 221.23 | | 221.23 | | |
| 79010 | 275 | Travel - Meals & Enter | FOX & HOUND #65057 | 226.01 | | 226.01 | | |
| 79010 | 275 | Travel - Meals & Enter | FRIDAYS_FRONT_ROW #060 | 19.98 | | 19.98 | | |
| 79010 | 275 | Travel - Meals & Enter | FROG & FIRKIN | 34.08 | | 34.08 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #0090SXN | 21.99 | | 21.99 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #017 SXN | 29.79 | | 29.79 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #033 SXN | 7.00 | | 7.00 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #036 SXN | 243.95 | | 243.95 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #042 SXN | 81.77 | | 81.77 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #058 SXN | 1,041.60 | | 1,041.60 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #119 SXN | 399.73 | | 399.73 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #138 SXN | 89.25 | | 89.25 | | |
| 79010 | 275 | Travel - Meals & Enter | FUJI SUSHI RESTA | 37.33 | | 37.33 | | |
| 79010 | 275 | Travel - Meals & Enter | FUNG LUM | 32.60 | | 32.60 | | |
| 79010 | 275 | Travel - Meals & Enter | GALAXY DINER 605 | 19.83 | | 19.83 | | |
| 79010 | 275 | Travel - Meals & Enter | GAVI ITALIAN RESTAURAN | 126.55 | | 126.55 | | |
| 79010 | 275 | Travel - Meals & Enter | GEES GARDEN RESTAURANT | 27.87 | | 27.87 | | |
| 79010 | 275 | Travel - Meals & Enter | GENTLE BENS BREWING CO | 29.59 | | 29.59 | | |
| 79010 | 275 | Travel - Meals & Enter | GINAS STROMBOLIS | 23.50 | | 23.50 | | |
| 79010 | 275 | Travel - Meals & Enter | GINSENG BBQ NO 2 | 39.22 | | 39.22 | | |
| 79010 | 275 | Travel - Meals & Enter | GODIVA CHOCOLATES #281 | 228.00 | | 228.00 | | |
| 79010 | 275 | Travel - Meals & Enter | GODIVA CHOCOLATES #361 | 194.00 | | 194.00 | | |
| 79010 | 275 | Travel - Meals & Enter | GOLDEN CORRAL 29724Q15 | 14.21 | | 14.21 | | |
| 79010 | 275 | Travel - Meals & Enter | GOLDEN CORRAL 730 | 58.80 | | 58.80 | | |
| 79010 | 275 | Travel - Meals & Enter | GONZALEZ Y GONZALEZ | 33.11 | | 33.11 | | |
| 79010 | 275 | Travel - Meals & Enter | GORDON BIERSCH-LAS VEG | 31.38 | | 31.38 | | |
| 79010 | 275 | Travel - Meals & Enter | GORDON BIERSCH-WASH DC | 54.64 | | 54.64 | | |
| 79010 | 275 | Travel - Meals & Enter | GREER LODGE | 313.75 | | 313.75 | | |
| 79010 | 275 | Travel - Meals & Enter | GRILL 417 | 67.75 | | 67.75 | | |
| 79010 | 275 | Travel - Meals & Enter | GUILLERMOS DOUBLE L RE | 301.56 | | 301.56 | | |
| 79010 | 275 | Travel - Meals & Enter | HARRAHS CASINO FOOD & | 94.50 | | 94.50 | | |
| 79010 | 275 | Travel - Meals & Enter | HARRAHS FRESH MKT BUFF | 20.31 | | 20.31 | | |
| 79010 | 275 | Travel - Meals & Enter | HILTON HOTELS STS BRNT | 23.56 | | 23.56 | | |
| 79010 | 275 | Travel - Meals & Enter | HILTON SANTA CLARA CAF | 3.95 | | 3.95 | | |
| 79010 | 275 | Travel - Meals & Enter | HILTON SEDONA RESORT F | 45.19 | | 45.19 | | |
| 79010 | 275 | Travel - Meals & Enter | HILTON TUCSON EAST F A | 13.49 | | 13.49 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST - LAS-AIRPT | 24.18 | | 24.18 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST DFW AIRPT #15 | 4.49 | | 4.49 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST-LAS-AIRPT #55 | 37.92 | | 37.92 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | HMS HOST-LAS-AIRPT #81 | 49.38 | | 49.38 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST-LAS-AIRPT#241 | 7.09 | | 7.09 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST-LAS-AIRPT#Q63 | 5.69 | | 5.69 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST-ORD AIRPT #6 | 35.06 | | 35.06 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST-ORD AIRPT #81 | 39.57 | | 39.57 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST-ORD AIRPT #83 | 36.75 | | 36.75 | | |
| 79010 | 275 | Travel - Meals & Enter | HMS HOST-PHX AIRPT Q63 | 7.65 | | 7.65 | | |
| 79010 | 275 | Travel - Meals & Enter | HMSHOST SAN AIRPT #02 | 13.10 | | 13.10 | | |
| 79010 | 275 | Travel - Meals & Enter | HMSHOST-LAS-AIRPT #000 | 87.24 | | 87.24 | | |
| 79010 | 275 | Travel - Meals & Enter | HMSHOST-LAX-AIR #00 | 38.43 | | 38.43 | | |
| 79010 | 275 | Travel - Meals & Enter | HMSHOST-PHX-AIR #00 | 42.70 | | 42.70 | | |
| 79010 | 275 | Travel - Meals & Enter | HMSHOST-PHX-AIR #04 | 6.47 | | 6.47 | | |
| 79010 | 275 | Travel - Meals & Enter | HMSHOST-SLC-AIRPT 0820 | 43.62 | | 43.62 | | |
| 79010 | 275 | Travel - Meals & Enter | HONEY BEARS BBQ 2 | 37.70 | | 37.70 | | |
| 79010 | 275 | Travel - Meals & Enter | HONEYBAKED-HAM #0056 | 93.14 | | 93.14 | | |
| 79010 | 275 | Travel - Meals & Enter | HOTEL BRUNSWICK | 42.00 | | 42.00 | | |
| 79010 | 275 | Travel - Meals & Enter | HOUSTON'S 480.922.7775 | 41.54 | | 41.54 | | |
| 79010 | 275 | Travel - Meals & Enter | HOUSTON'S 602.957.9700 | 259.94 | | 259.94 | | |
| 79010 | 275 | Travel - Meals & Enter | HRC-NEW YORK 10011013 | 41.35 | | 41.35 | | |
| 79010 | 275 | Travel - Meals & Enter | HRC-PHOENIX 10011435 | 24.00 | | 24.00 | | |
| 79010 | 275 | Travel - Meals & Enter | HRC-SN ANTONIO10011120 | 50.50 | | 50.50 | | |
| 79010 | 275 | Travel - Meals & Enter | HUNAN WEST | 18.16 | | 18.16 | | |
| 79010 | 275 | Travel - Meals & Enter | HYATT HOTELS SAN FRANC | 31.25 | | 31.25 | | |
| 79010 | 275 | Travel - Meals & Enter | HYATT REGENCY WASHINGT | 4.00 | | 4.00 | | |
| 79010 | 275 | Travel - Meals & Enter | I LOVE TERIYAKI | 6.93 | | 6.93 | | |
| 79010 | 275 | Travel - Meals & Enter | ICHIBAN SUSHI RESTAURA | 35.33 | | 35.33 | | |
| 79010 | 275 | Travel - Meals & Enter | IHOP #1513 18515130 | 23.15 | | 23.15 | | |
| 79010 | 275 | Travel - Meals & Enter | IHOP #1517 21815170 | 80.95 | | 80.95 | | |
| 79010 | 275 | Travel - Meals & Enter | IHOP #1522 34615229 | 47.33 | | 47.33 | | |
| 79010 | 275 | Travel - Meals & Enter | IKES COFFEE & TEA N ST | 48.86 | | 48.86 | | |
| 79010 | 275 | Travel - Meals & Enter | IL FORNAIO - LAS VEGAS | 59.51 | | 59.51 | | |
| 79010 | 275 | Travel - Meals & Enter | IN-N-OUT BURGER 000000 | 4.01 | | 4.01 | | |
| 79010 | 275 | Travel - Meals & Enter | IN-N-OUT BURGERS | 32.75 | | 32.75 | | |
| 79010 | 275 | Travel - Meals & Enter | INTERMEZZO | 80.48 | | 80.48 | | |
| 79010 | 275 | Travel - Meals & Enter | INTERNATIONAL TRANSACTION | 8.97 | | 8.97 | | |
| 79010 | 275 | Travel - Meals & Enter | IRON CACTUS | 18.08 | | 18.08 | | |
| 79010 | 275 | Travel - Meals & Enter | IT'S A GRIND Q21 | 33.95 | | 33.95 | | |
| 79010 | 275 | Travel - Meals & Enter | JACKSONS GRILL | 17.00 | | 17.00 | | |
| 79010 | 275 | Travel - Meals & Enter | JACKSONS ON THIRD LLC | 49.22 | | 49.22 | | |
| 79010 | 275 | Travel - Meals & Enter | JALEO | 84.31 | | 84.31 | | |
| 79010 | 275 | Travel - Meals & Enter | JASON'S DELI | 2,986.92 | | 2,986.92 | | |
| 79010 | 275 | Travel - Meals & Enter | JAVA BLUES | 262.11 | | 262.11 | | |
| 79010 | 275 | Travel - Meals & Enter | JAZZMANS 1 | 3.95 | | 3.95 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | JERRY BOB'S | 44.56 | | 44.56 | | |
| 79010 | 275 | Travel - Meals & Enter | JOES CRAB SHACK-LAUGHL | 23.65 | | 23.65 | | |
| 79010 | 275 | Travel - Meals & Enter | JOE'S CRAB SHACK-TEMPE | 37.15 | | 37.15 | | |
| 79010 | 275 | Travel - Meals & Enter | JOE'S CRAB-AURORA, CO | 93.21 | | 93.21 | | |
| 79010 | 275 | Travel - Meals & Enter | JOE'S CRAB-SA #3 RVERW | 24.60 | | 24.60 | | |
| 79010 | 275 | Travel - Meals & Enter | JOE'S CRAB-TUCSON | 261.72 | | 261.72 | | |
| 79010 | 275 | Travel - Meals & Enter | JOES PLACE | 12.76 | | 12.76 | | |
| 79010 | 275 | Travel - Meals & Enter | JOHNNY ROCKETS-TUC | 20.26 | | 20.26 | | |
| 79010 | 275 | Travel - Meals & Enter | JOSEPHINE'S MODERN | 113.53 | | 113.53 | | |
| 79010 | 275 | Travel - Meals & Enter | JUNIOR'S NYC | 51.33 | | 51.33 | | |
| 79010 | 275 | Travel - Meals & Enter | KELLYS COFFEE AND | 9.55 | | 9.55 | | |
| 79010 | 275 | Travel - Meals & Enter | KFC #10 Q20 | 30.39 | | 30.39 | | |
| 79010 | 275 | Travel - Meals & Enter | KG'S WESTSIDE CAFE | 19.03 | | 19.03 | | |
| 79010 | 275 | Travel - Meals & Enter | KIM CHI | 34.62 | | 34.62 | | |
| 79010 | 275 | Travel - Meals & Enter | KINCAID S | 75.18 | | 75.18 | | |
| 79010 | 275 | Travel - Meals & Enter | KINGMAN CO STEAKHOUSE | 24.00 | | 24.00 | | |
| 79010 | 275 | Travel - Meals & Enter | KINGMAN DELI, THE | 24.00 | | 24.00 | | |
| 79010 | 275 | Travel - Meals & Enter | KING'S ORIENTAL FAST F | 21.05 | | 21.05 | | |
| 79010 | 275 | Travel - Meals & Enter | KINZIE CHOPHOUSE | 58.88 | | 58.88 | | |
| 79010 | 275 | Travel - Meals & Enter | KMART 00049SZI | 334.17 | | 334.17 | | |
| 79010 | 275 | Travel - Meals & Enter | KOBE STEAKHOUSE - TEMP | 71.51 | | 71.51 | | |
| 79010 | 275 | Travel - Meals & Enter | KONA CAFE | 43.75 | | 43.75 | | |
| 79010 | 275 | Travel - Meals & Enter | KRISPY KREME 15 05 | 14.36 | | 14.36 | | |
| 79010 | 275 | Travel - Meals & Enter | LA CANASTA #1 | 28.39 | | 28.39 | | |
| 79010 | 275 | Travel - Meals & Enter | LA CANASTA CAPITOLIO | 39.28 | | 39.28 | | |
| 79010 | 275 | Travel - Meals & Enter | LA FONDA MEXICAN FOODS | 25.41 | | 25.41 | | |
| 79010 | 275 | Travel - Meals & Enter | LA PARILLA SUIZA | 205.14 | | 205.14 | | |
| 79010 | 275 | Travel - Meals & Enter | LA PLAYA HOTEL RESTAUR | 98.75 | | 98.75 | | |
| 79010 | 275 | Travel - Meals & Enter | LA SALSA 76 | 25.87 | | 25.87 | | |
| 79010 | 275 | Travel - Meals & Enter | LA SANDIA CAFE 1 | 9.04 | | 9.04 | | |
| 79010 | 275 | Travel - Meals & Enter | LANDRY'S-SA DOWNTOWN | 57.55 | | 57.55 | | |
| 79010 | 275 | Travel - Meals & Enter | LAS CAZUELITAS LLC | 27.95 | | 27.95 | | |
| 79010 | 275 | Travel - Meals & Enter | LAS VEGAS SPORTS LOUNG | 14.00 | | 14.00 | | |
| 79010 | 275 | Travel - Meals & Enter | LAS VIGAS STEAK RANCH | 33.37 | | 33.37 | | |
| 79010 | 275 | Travel - Meals & Enter | LAWRY'S | 134.21 | | 134.21 | | |
| 79010 | 275 | Travel - Meals & Enter | LAX AIRPORT-PUCKS T7 | 16.23 | | 16.23 | | |
| 79010 | 275 | Travel - Meals & Enter | LE CAVES BAKERY | 11.98 | | 11.98 | | |
| 79010 | 275 | Travel - Meals & Enter | LEBANESE TAVERNA | 33.80 | | 33.80 | | |
| 79010 | 275 | Travel - Meals & Enter | LEGENDS OF SAN FRANCIS | 20.21 | | 20.21 | | |
| 79010 | 275 | Travel - Meals & Enter | LERUA'S | 41.38 | | 41.38 | | |
| 79010 | 275 | Travel - Meals & Enter | LEVY GRP SALE 90085002 | 30.55 | | 30.55 | | |
| 79010 | 275 | Travel - Meals & Enter | LIGHTNING RIDGE CAFE | 2,348.54 | | 2,348.54 | | |
| 79010 | 275 | Travel - Meals & Enter | LITTLE ANTHONY S DINER | 876.36 | | 876.36 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | LITTLE CAESARS 3168 | 12.43 | | 12.43 | | |
| 79010 | 275 | Travel - Meals & Enter | LITTLE MEXICO RESTAURA | 82.60 | | 82.60 | | |
| 79010 | 275 | Travel - Meals & Enter | LODGE ON THE DESERT | 101.00 | | 101.00 | | |
| 79010 | 275 | Travel - Meals & Enter | LOMBARDI'S RESTAURANT | 245.21 | | 245.21 | | |
| 79010 | 275 | Travel - Meals & Enter | LONE STAR 00128017 | 15.46 | | 15.46 | | |
| 79010 | 275 | Travel - Meals & Enter | LONGHORN #248 | 33.54 | | 33.54 | | |
| 79010 | 275 | Travel - Meals & Enter | LOS BETOS MEXICAN | 19.13 | | 19.13 | | |
| 79010 | 275 | Travel - Meals & Enter | LOS RANCHOS RESTAURANT | 75.03 | | 75.03 | | |
| 79010 | 275 | Travel - Meals & Enter | LUKES ITALIAN BEEF | 28.00 | | 28.00 | | |
| 79010 | 275 | Travel - Meals & Enter | LV HILTON BUFFET | 14.00 | | 14.00 | | |
| 79010 | 275 | Travel - Meals & Enter | MACARONI GR16300001636 | 1,037.91 | | 1,037.91 | | |
| 79010 | 275 | Travel - Meals & Enter | MACARONI GR23300002337 | 22.13 | | 22.13 | | |
| 79010 | 275 | Travel - Meals & Enter | MACARONI GR30100003012 | 97.26 | | 97.26 | | |
| 79010 | 275 | Travel - Meals & Enter | MACAYO DEPOT | 72.38 | | 72.38 | | |
| 79010 | 275 | Travel - Meals & Enter | MAGPIES GOURMET PIZZA | 166.99 | | 166.99 | | |
| 79010 | 275 | Travel - Meals & Enter | MAIN STREET CATERI | 23.00 | | 23.00 | | |
| 79010 | 275 | Travel - Meals & Enter | MAMA LOUISAS | 97.03 | | 97.03 | | |
| 79010 | 275 | Travel - Meals & Enter | MAMA'S FAMOUS # 2 | 28.46 | | 28.46 | | |
| 79010 | 275 | Travel - Meals & Enter | MAMBO CAFE2 | 45.76 | | 45.76 | | |
| 79010 | 275 | Travel - Meals & Enter | MANDARIN ORIENTAL SAN | 58.21 | | 58.21 | | |
| 79010 | 275 | Travel - Meals & Enter | MARGARITAVILLE RESTAUR | 21.00 | | 21.00 | | |
| 79010 | 275 | Travel - Meals & Enter | MARIE CALLENDER'S REST | 19.26 | | 19.26 | | |
| 79010 | 275 | Travel - Meals & Enter | MARISCOS CHIHUAHUA | 29.71 | | 29.71 | | |
| 79010 | 275 | Travel - Meals & Enter | MARKET CITY CAFE | 25.96 | | 25.96 | | |
| 79010 | 275 | Travel - Meals & Enter | MARRIOTT 33758 SLC | 50.00 | | 50.00 | | |
| 79010 | 275 | Travel - Meals & Enter | MARRIOTT 337E4 DESERT | 11.85 | | 11.85 | | |
| 79010 | 275 | Travel - Meals & Enter | MATSUTAKE - NATL AIRPO | 20.98 | | 20.98 | | |
| 79010 | 275 | Travel - Meals & Enter | MCCORMICK & SCHMICK #7 | 122.20 | | 122.20 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD'S F11538 Q17 | 11.85 | | 11.85 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD'S F18788 Q17 | 11.56 | | 11.56 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD'S F22627 Q17 | 16.71 | | 16.71 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD'S F24530 Q17 | 6.67 | | 6.67 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD'S F8010 Q17 | 36.10 | | 36.10 | | |
| 79010 | 275 | Travel - Meals & Enter | MCMAHON'S STEAKHOUSE | 117.16 | | 117.16 | | |
| 79010 | 275 | Travel - Meals & Enter | MEI HON | 85.18 | | 85.18 | | |
| 79010 | 275 | Travel - Meals & Enter | MEI WAH RESTAURANT | 14.80 | | 14.80 | | |
| 79010 | 275 | Travel - Meals & Enter | MERLOT BISTRO | 44.58 | | 44.58 | | |
| 79010 | 275 | Travel - Meals & Enter | METRO GRILL PARK PLACE | 469.50 | | 469.50 | | |
| 79010 | 275 | Travel - Meals & Enter | METROPOLITAN GRILL | 174.57 | | 174.57 | | |
| 79010 | 275 | Travel - Meals & Enter | MI AMIGOS-AZ CENTE | 59.83 | | 59.83 | | |
| 79010 | 275 | Travel - Meals & Enter | MI NIDITO | 63.24 | | 63.24 | | |
| 79010 | 275 | Travel - Meals & Enter | MICHAS | 1,139.13 | | 1,139.13 | | |
| 79010 | 275 | Travel - Meals & Enter | MICHAS DEL NORTE | 81.51 | | 81.51 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | MICROBREWERY | 129.74 | | 129.74 | | |
| 79010 | 275 | Travel - Meals & Enter | MIGUELS ON ORACLE | 687.79 | | 687.79 | | |
| 79010 | 275 | Travel - Meals & Enter | MIMIS CAFE 00000356 | 80.58 | | 80.58 | | |
| 79010 | 275 | Travel - Meals & Enter | MING | 24.98 | | 24.98 | | |
| 79010 | 275 | Travel - Meals & Enter | MING'S TABLE | 27.62 | | 27.62 | | |
| 79010 | 275 | Travel - Meals & Enter | MIRAGE HOTEL - STACK | 19.00 | | 19.00 | | |
| 79010 | 275 | Travel - Meals & Enter | MOLLY BUTLER LODGE | 186.52 | | 186.52 | | |
| 79010 | 275 | Travel - Meals & Enter | MONTANA AVENUE | 56.23 | | 56.23 | | |
| 79010 | 275 | Travel - Meals & Enter | MORGANS FOOD & SPIRITS | 32.05 | | 32.05 | | |
| 79010 | 275 | Travel - Meals & Enter | MR. C'S RESTAURANT | 118.72 | | 118.72 | | |
| 79010 | 275 | Travel - Meals & Enter | MRS. FIELDS BAKERY CAF | 92.71 | | 92.71 | | |
| 79010 | 275 | Travel - Meals & Enter | MUDSHARK BREWING CO | 89.45 | | 89.45 | | |
| 79010 | 275 | Travel - Meals & Enter | NADINES PASTRY SHOPPE | 405.99 | | 405.99 | | |
| 79010 | 275 | Travel - Meals & Enter | NAGE RESTAURANT, D.C. | 49.00 | | 49.00 | | |
| 79010 | 275 | Travel - Meals & Enter | NATHAN S FAMOUS HOT DO | 11.30 | | 11.30 | | |
| 79010 | 275 | Travel - Meals & Enter | NAU DINING#94010007 | 233.74 | | 233.74 | | |
| 79010 | 275 | Travel - Meals & Enter | NAVY PIER 71229 | 22.00 | | 22.00 | | |
| 79010 | 275 | Travel - Meals & Enter | NELLIES KITCHEN | 12.18 | | 12.18 | | |
| 79010 | 275 | Travel - Meals & Enter | NEW YORK LUNCHEONETTE | 47.45 | | 47.45 | | |
| 79010 | 275 | Travel - Meals & Enter | NEW YORK PIZZA DEPT | 8.92 | | 8.92 | | |
| 79010 | 275 | Travel - Meals & Enter | NIJI JAPANESE GRILLE | 12.66 | | 12.66 | | |
| 79010 | 275 | Travel - Meals & Enter | NOTHING BUT NOODLE | 33.58 | | 33.58 | | |
| 79010 | 275 | Travel - Meals & Enter | OAXACA RESTAURANTE | 416.48 | | 416.48 | | |
| 79010 | 275 | Travel - Meals & Enter | O'CHARLEY'S #213 | 34.27 | | 34.27 | | |
| 79010 | 275 | Travel - Meals & Enter | OCOTILLO GOLF RESORT | 57.67 | | 57.67 | | |
| 79010 | 275 | Travel - Meals & Enter | OISHI SUSHI & TERIYAKI | 15.32 | | 15.32 | | |
| 79010 | 275 | Travel - Meals & Enter | OLD PEKING CHINESE RES | 50.10 | | 50.10 | | |
| 79010 | 275 | Travel - Meals & Enter | OLD PUEBLO GRILLE | 1,387.36 | | 1,387.36 | | |
| 79010 | 275 | Travel - Meals & Enter | OMARS HIGHWAY CHEF RES | 79.81 | | 79.81 | | |
| 79010 | 275 | Travel - Meals & Enter | ON THE BORD12600001263 | 247.47 | | 247.47 | | |
| 79010 | 275 | Travel - Meals & Enter | ON THE BORDER 00000315 | 34.68 | | 34.68 | | |
| 79010 | 275 | Travel - Meals & Enter | ORACLE CAFE 2 Q70 | 17.02 | | 17.02 | | |
| 79010 | 275 | Travel - Meals & Enter | OREGANO S | 60.54 | | 60.54 | | |
| 79010 | 275 | Travel - Meals & Enter | OREGANOS | 44.01 | | 44.01 | | |
| 79010 | 275 | Travel - Meals & Enter | OREILLYS PUB | 42.90 | | 42.90 | | |
| 79010 | 275 | Travel - Meals & Enter | ORLEANS FR MKT BUFFET | 34.75 | | 34.75 | | |
| 79010 | 275 | Travel - Meals & Enter | OSHA THAI RESTAURANT & | 37.47 | | 37.47 | | |
| 79010 | 275 | Travel - Meals & Enter | OUR DAILY BREAD | 15.03 | | 15.03 | | |
| 79010 | 275 | Travel - Meals & Enter | OUTBACK #0315 | 60.84 | | 60.84 | | |
| 79010 | 275 | Travel - Meals & Enter | OUTBACK #0317 | 58.42 | | 58.42 | | |
| 79010 | 275 | Travel - Meals & Enter | OUTBACK #3333 | 43.83 | | 43.83 | | |
| 79010 | 275 | Travel - Meals & Enter | P.F. CHANG'S #5800 | 38.68 | | 38.68 | | |
| 79010 | 275 | Travel - Meals & Enter | P.F. CHANG'S #8000 | 228.71 | | 228.71 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | P.F. CHANG'S CHINA BIS | 51.19 | | 51.19 | | |
| 79010 | 275 | Travel - Meals & Enter | PALM REST VEGAS | 308.30 | | 308.30 | | |
| 79010 | 275 | Travel - Meals & Enter | PANDA EXPRESS 00007Q42 | 7.60 | | 7.60 | | |
| 79010 | 275 | Travel - Meals & Enter | PANDA EXPRESS 00011Q42 | 30.56 | | 30.56 | | |
| 79010 | 275 | Travel - Meals & Enter | PAOLOS GEORGETOWN | 37.19 | | 37.19 | | |
| 79010 | 275 | Travel - Meals & Enter | PAPA JOHNS #2008 | 177.43 | | 177.43 | | |
| 79010 | 275 | Travel - Meals & Enter | PAPA JOHNS #2008.COM | 43.10 | | 43.10 | | |
| 79010 | 275 | Travel - Meals & Enter | PAPA JOHNS #3115.COM | 60.41 | | 60.41 | | |
| 79010 | 275 | Travel - Meals & Enter | PARADIES WASH NAT L | 7.01 | | 7.01 | | |
| 79010 | 275 | Travel - Meals & Enter | PARIS LE VILLAGE BUFFE | 92.21 | | 92.21 | | |
| 79010 | 275 | Travel - Meals & Enter | PARK CENTRAL DELI | 38.69 | | 38.69 | | |
| 79010 | 275 | Travel - Meals & Enter | PARRILLA DEL REY | 25.30 | | 25.30 | | |
| 79010 | 275 | Travel - Meals & Enter | PASTICHE MODERN EATERY | 37.60 | | 37.60 | | |
| 79010 | 275 | Travel - Meals & Enter | PASTO | 179.45 | | 179.45 | | |
| 79010 | 275 | Travel - Meals & Enter | PATS PLACE | 20.40 | | 20.40 | | |
| 79010 | 275 | Travel - Meals & Enter | PEETS SFO #4 | 13.64 | | 13.64 | | |
| 79010 | 275 | Travel - Meals & Enter | PEI WEI ASIAN DINER-00 | 98.42 | | 98.42 | | |
| 79010 | 275 | Travel - Meals & Enter | PEI WEI ASIAN DINER-01 | 20.54 | | 20.54 | | |
| 79010 | 275 | Travel - Meals & Enter | PERSIAN ROOM | 160.52 | | 160.52 | | |
| 79010 | 275 | Travel - Meals & Enter | PETER PIPER PIZZA | 19.97 | | 19.97 | | |
| 79010 | 275 | Travel - Meals & Enter | PETER PIPER PIZZA #162 | 28.45 | | 28.45 | | |
| 79010 | 275 | Travel - Meals & Enter | PF CHANGS #9914 | 27.29 | | 27.29 | | |
| 79010 | 275 | Travel - Meals & Enter | PHOENIX AIRPORT | 8.92 | | 8.92 | | |
| 79010 | 275 | Travel - Meals & Enter | PINNACLE PEAK | 72.00 | | 72.00 | | |
| 79010 | 275 | Travel - Meals & Enter | PIZZA H011645 01201078 | 31.53 | | 31.53 | | |
| 79010 | 275 | Travel - Meals & Enter | PIZZA HUT 07030Q00 | 25.12 | | 25.12 | | |
| 79010 | 275 | Travel - Meals & Enter | PIZZA HUT #10557500Q34 | 54.54 | | 54.54 | | |
| 79010 | 275 | Travel - Meals & Enter | PIZZA HUT #14357500Q34 | 240.13 | | 240.13 | | |
| 79010 | 275 | Travel - Meals & Enter | PIZZA HUT #14357543Q | 365.00 | | 365.00 | | |
| 79010 | 275 | Travel - Meals & Enter | PIZZA HUT C19 | 4.82 | | 4.82 | | |
| 79010 | 275 | Travel - Meals & Enter | PIZZA HUT C5 | 9.02 | | 9.02 | | |
| 79010 | 275 | Travel - Meals & Enter | PLANET HOLLYWOOD | 80.01 | | 80.01 | | |
| 79010 | 275 | Travel - Meals & Enter | PLAZA CAFE | 5.95 | | 5.95 | | |
| 79010 | 275 | Travel - Meals & Enter | PORT A PIT CATERING | 1,349.30 | | 1,349.30 | | |
| 79010 | 275 | Travel - Meals & Enter | PORTLANDS | 91.67 | | 91.67 | | |
| 79010 | 275 | Travel - Meals & Enter | POTBELLY SANDWCH58 Q86 | 7.34 | | 7.34 | | |
| 79010 | 275 | Travel - Meals & Enter | PRIME RIB GRILL | 15.73 | | 15.73 | | |
| 79010 | 275 | Travel - Meals & Enter | QUESADILLIA'S GRILL/ M | 14.53 | | 14.53 | | |
| 79010 | 275 | Travel - Meals & Enter | QUIZNO S ALB | 8.84 | | 8.84 | | |
| 79010 | 275 | Travel - Meals & Enter | QUIZNOS CLASSIC SUBS | 7.22 | | 7.22 | | |
| 79010 | 275 | Travel - Meals & Enter | QUIZNO'S SUB #2515 | 22.09 | | 22.09 | | |
| 79010 | 275 | Travel - Meals & Enter | QUIZNOS SUB #3255 Q22 | 56.47 | | 56.47 | | |
| 79010 | 275 | Travel - Meals & Enter | QUIZNOS SUB #4297 Q19 | 28.54 | | 28.54 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | QUIZNOS SUB #9515 | 8.09 | | 8.09 | | |
| 79010 | 275 | Travel - Meals & Enter | R&G LOUNGE | 43.90 | | 43.90 | | |
| 79010 | 275 | Travel - Meals & Enter | RADISON WILSHIRE | 107.00 | | 107.00 | | |
| 79010 | 275 | Travel - Meals & Enter | RAINFOREST SAN ANTONIO | 28.76 | | 28.76 | | |
| 79010 | 275 | Travel - Meals & Enter | RAINFOREST-AZ REST. | 38.62 | | 38.62 | | |
| 79010 | 275 | Travel - Meals & Enter | RAINFOREST-DISNEY WRLD | 36.63 | | 36.63 | | |
| 79010 | 275 | Travel - Meals & Enter | RAINFOREST-GRAPEVINE | 56.34 | | 56.34 | | |
| 79010 | 275 | Travel - Meals & Enter | RAINFOREST-MGM GRAND | 19.99 | | 19.99 | | |
| 79010 | 275 | Travel - Meals & Enter | RED LOBSTER US00006007 | 46.48 | | 46.48 | | |
| 79010 | 275 | Travel - Meals & Enter | RED LOBSTER US00008698 | 56.56 | | 56.56 | | |
| 79010 | 275 | Travel - Meals & Enter | RED LOBSTER US00063032 | 25.75 | | 25.75 | | |
| 79010 | 275 | Travel - Meals & Enter | RED ROBIN | 68.07 | | 68.07 | | |
| 79010 | 275 | Travel - Meals & Enter | RED ROBIN NO 195 | 21.58 | | 21.58 | | |
| 79010 | 275 | Travel - Meals & Enter | RED ROBIN RESTAURANT | 127.18 | | 127.18 | | |
| 79010 | 275 | Travel - Meals & Enter | RENDEZVOUS RANCH INC | 5,170.00 | | 5,170.00 | | |
| 79010 | 275 | Travel - Meals & Enter | RIGO S RESTAURANT | 159.78 | | 159.78 | | |
| 79010 | 275 | Travel - Meals & Enter | RINCON MARKET | 758.33 | | 758.33 | | |
| 79010 | 275 | Travel - Meals & Enter | RINCON MARKET SRI | 45.88 | | 45.88 | | |
| 79010 | 275 | Travel - Meals & Enter | RISKY BUSINESS #4 | 302.38 | | 302.38 | | |
| 79010 | 275 | Travel - Meals & Enter | RIVA RISTORANTE | 48.68 | | 48.68 | | |
| 79010 | 275 | Travel - Meals & Enter | ROCK BOTTOM 1077 | 84.73 | | 84.73 | | |
| 79010 | 275 | Travel - Meals & Enter | RONS PRODUCE CO INC | 261.10 | | 261.10 | | |
| 79010 | 275 | Travel - Meals & Enter | ROSINELLA | 19.75 | | 19.75 | | |
| 79010 | 275 | Travel - Meals & Enter | ROXANNE CAFE | 30.00 | | 30.00 | | |
| 79010 | 275 | Travel - Meals & Enter | ROYS #2303 | 143.70 | | 143.70 | | |
| 79010 | 275 | Travel - Meals & Enter | RUBIO'S AGUA FRIA #52 | 11.86 | | 11.86 | | |
| 79010 | 275 | Travel - Meals & Enter | RUBIO'S AHWATUKEE #35 | 29.78 | | 29.78 | | |
| 79010 | 275 | Travel - Meals & Enter | RUBY RIVER #405 | 83.40 | | 83.40 | | |
| 79010 | 275 | Travel - Meals & Enter | RUBY TUESDAY #2632 | 14.98 | | 14.98 | | |
| 79010 | 275 | Travel - Meals & Enter | RUMBI, AZ PROMENADE | 11.41 | | 11.41 | | |
| 79010 | 275 | Travel - Meals & Enter | RUSTY S FAMILY RESTAUR | 43.00 | | 43.00 | | |
| 79010 | 275 | Travel - Meals & Enter | RUSTY'S | 82.70 | | 82.70 | | |
| 79010 | 275 | Travel - Meals & Enter | SABELLA & LATORRE SEAF | 15.40 | | 15.40 | | |
| 79010 | 275 | Travel - Meals & Enter | SACHIKO SUSHI II | 224.88 | | 224.88 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00002550 | 359.60 | | 359.60 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00002683 | 4.50 | | 4.50 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00002Q | 70.24 | | 70.24 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00002SC9 | 301.94 | | 301.94 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00012559 | 27.42 | | 27.42 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00012757 | 28.31 | | 28.31 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00015214 | 76.33 | | 76.33 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00015SC9 | 38.66 | | 38.66 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00018747 | 108.52 | | 108.52 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00018SC9 | 5.99 | | 5.99 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00020446 | 5.01 | | 5.01 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00020768 | 11.25 | | 11.25 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00020SC9 | 6.67 | | 6.67 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00026112 | 33.61 | | 33.61 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00026SC9 | 89.82 | | 89.82 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE 00019851 | 8.83 | | 8.83 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE 00019877 | 75.27 | | 75.27 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE 00019901 | 33.13 | | 33.13 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE 00019Q | 15.98 | | 15.98 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE 00019SC9 | 420.68 | | 420.68 | | |
| 79010 | 275 | Travel - Meals & Enter | SAKURA EAST | 179.39 | | 179.39 | | |
| 79010 | 275 | Travel - Meals & Enter | SALSA FIESTA | 29.13 | | 29.13 | | |
| 79010 | 275 | Travel - Meals & Enter | SAM HUGHES PLACE | 1,051.95 | | 1,051.95 | | |
| 79010 | 275 | Travel - Meals & Enter | SAM'S CAFE-AZ CENTER | 42.84 | | 42.84 | | |
| 79010 | 275 | Travel - Meals & Enter | SAN MARTIN | 48.20 | | 48.20 | | |
| 79010 | 275 | Travel - Meals & Enter | SASSOS PIZZA & DELI | 12.13 | | 12.13 | | |
| 79010 | 275 | Travel - Meals & Enter | SAUCE | 47.83 | | 47.83 | | |
| 79010 | 275 | Travel - Meals & Enter | SAUSAGE DELI | 209.35 | | 209.35 | | |
| 79010 | 275 | Travel - Meals & Enter | SBC GATE 6 | 4.35 | | 4.35 | | |
| 79010 | 275 | Travel - Meals & Enter | SCALA'S/CAFFE/STARLIGH | 24.34 | | 24.34 | | |
| 79010 | 275 | Travel - Meals & Enter | SCHLOTZSKY'S DELI #134 | 7.22 | | 7.22 | | |
| 79010 | 275 | Travel - Meals & Enter | SCHLOTZSKYS DELI VALEN | 218.19 | | 218.19 | | |
| 79010 | 275 | Travel - Meals & Enter | SEE'S CANDY #404 | 64.25 | | 64.25 | | |
| 79010 | 275 | Travel - Meals & Enter | SERIOUS TEXAS BAR B Q | 48.00 | | 48.00 | | |
| 79010 | 275 | Travel - Meals & Enter | SF SOUP CO CROCKER Q35 | 8.58 | | 8.58 | | |
| 79010 | 275 | Travel - Meals & Enter | SHOGUN RESTAURANT | 33.77 | | 33.77 | | |
| 79010 | 275 | Travel - Meals & Enter | SHUGRUES RESTAURANT | 95.30 | | 95.30 | | |
| 79010 | 275 | Travel - Meals & Enter | SIAMESE KITCHEN | 25.97 | | 25.97 | | |
| 79010 | 275 | Travel - Meals & Enter | SILVER SADDLE STEAKHOU | 648.66 | | 648.66 | | |
| 79010 | 275 | Travel - Meals & Enter | SIRRICO'S | 6.68 | | 6.68 | | |
| 79010 | 275 | Travel - Meals & Enter | SIZZLER RESTAURANT | 21.99 | | 21.99 | | |
| 79010 | 275 | Travel - Meals & Enter | SKY BLUE WASABI RESTAU | 51.90 | | 51.90 | | |
| 79010 | 275 | Travel - Meals & Enter | SKY SNAX C CONCOURSE | 4.32 | | 4.32 | | |
| 79010 | 275 | Travel - Meals & Enter | SLUGGO'S SPORTS GRILL | 26.52 | | 26.52 | | |
| 79010 | 275 | Travel - Meals & Enter | SOTO'S P/K OUTPOST | 25.78 | | 25.78 | | |
| 79010 | 275 | Travel - Meals & Enter | ST. MARY'S MEXICAN FOO | 19.55 | | 19.55 | | |
| 79010 | 275 | Travel - Meals & Enter | STAR TREK | 74.07 | | 74.07 | | |
| 79010 | 275 | Travel - Meals & Enter | STARBUCKS UCO 00057Q48 | 7.90 | | 7.90 | | |
| 79010 | 275 | Travel - Meals & Enter | STARBUCKS USA 00029Q48 | 9.75 | | 9.75 | | |
| 79010 | 275 | Travel - Meals & Enter | STARBUCKS USA 00055Q48 | 20.00 | | 20.00 | | |
| 79010 | 275 | Travel - Meals & Enter | STARBUCKS USA 00056Q48 | 7.35 | | 7.35 | | |
| 79010 | 275 | Travel - Meals & Enter | STARBUCKS USA 00069Q48 | 23.57 | | 23.57 | | |
| 79010 | 275 | Travel - Meals & Enter | STARBUCKS USA 00087Q48 | 19.67 | | 19.67 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | STARBUCKS USA 00088Q48 | 43.24 | | 43.24 | | |
| 79010 | 275 | Travel - Meals & Enter | STARR PASS GOLF CLUB | 673.02 | | 673.02 | | |
| 79010 | 275 | Travel - Meals & Enter | STOUDEMIRES | 29.46 | | 29.46 | | |
| 79010 | 275 | Travel - Meals & Enter | STROMBOLLI'S PIZZA | 81.74 | | 81.74 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY | 134.35 | | 134.35 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY 00263Q16 | 11.43 | | 11.43 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY 34169 | 17.72 | | 17.72 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY #1840 | 18.89 | | 18.89 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY #25727 Q89 | 9.49 | | 9.49 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY #31741 Q16 | 21.67 | | 21.67 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY 1840 00018Q16 | 14.03 | | 14.03 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY 25070 00250Q16 | 74.60 | | 74.60 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY 34169 00341Q16 | 11.57 | | 11.57 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY NO. 25070 | 13.11 | | 13.11 | | |
| 79010 | 275 | Travel - Meals & Enter | SULLIVAN'S STE00085258 | 94.23 | | 94.23 | | |
| 79010 | 275 | Travel - Meals & Enter | SUSHI CHO | 90.54 | | 90.54 | | |
| 79010 | 275 | Travel - Meals & Enter | SUSHI GARDEN, LLC | 25.00 | | 25.00 | | |
| 79010 | 275 | Travel - Meals & Enter | SWEET TOMATOES #48 | 58.02 | | 58.02 | | |
| 79010 | 275 | Travel - Meals & Enter | T.G.I. FRIDAY'S COSTA | 34.08 | | 34.08 | | |
| 79010 | 275 | Travel - Meals & Enter | T.G.I. FRIDAY'S TUCSON | 209.74 | | 209.74 | | |
| 79010 | 275 | Travel - Meals & Enter | TADICH GRILL | 27.90 | | 27.90 | | |
| 79010 | 275 | Travel - Meals & Enter | TAQUERIA CANONITA #575 | 43.83 | | 43.83 | | |
| 79010 | 275 | Travel - Meals & Enter | TARBELL'S | 210.53 | | 210.53 | | |
| 79010 | 275 | Travel - Meals & Enter | TAYLORS PRIME STEAKS | 177.00 | | 177.00 | | |
| 79010 | 275 | Travel - Meals & Enter | TED'S COUNTRY STOR | 1,067.51 | | 1,067.51 | | |
| 79010 | 275 | Travel - Meals & Enter | TERESA'S MOSAIC CAFE | 107.58 | | 107.58 | | |
| 79010 | 275 | Travel - Meals & Enter | TEXAS LAND & CATTLE#71 | 56.67 | | 56.67 | | |
| 79010 | 275 | Travel - Meals & Enter | TGI_FRIDAYS #0792 | 34.39 | | 34.39 | | |
| 79010 | 275 | Travel - Meals & Enter | THE ARTIST'S PALATE | 18.00 | | 18.00 | | |
| 79010 | 275 | Travel - Meals & Enter | THE BAGELRY Q17 | 17.95 | | 17.95 | | |
| 79010 | 275 | Travel - Meals & Enter | THE BALL PARK CONCESSI | 50.00 | | 50.00 | | |
| 79010 | 275 | Travel - Meals & Enter | THE BOMBAY CLUB | 246.20 | | 246.20 | | |
| 79010 | 275 | Travel - Meals & Enter | THE CHICAGO CHOP HOUSE | 60.36 | | 60.36 | | |
| 79010 | 275 | Travel - Meals & Enter | THE EGG CONNECTION | 37.00 | | 37.00 | | |
| 79010 | 275 | Travel - Meals & Enter | THE GOOD EGG WILLIAMS | 318.21 | | 318.21 | | |
| 79010 | 275 | Travel - Meals & Enter | THE GRAND LUX CAFE | 64.17 | | 64.17 | | |
| 79010 | 275 | Travel - Meals & Enter | THE GREEN FLASH | 23.61 | | 23.61 | | |
| 79010 | 275 | Travel - Meals & Enter | THE JAVA EDGE Q04 | 8.22 | | 8.22 | | |
| 79010 | 275 | Travel - Meals & Enter | THE OLIVE GARD00012195 | 341.75 | | 341.75 | | |
| 79010 | 275 | Travel - Meals & Enter | THE OLIVE GARD00014514 | 68.16 | | 68.16 | | |
| 79010 | 275 | Travel - Meals & Enter | THE OLIVE GARD00016220 | 442.59 | | 442.59 | | |
| 79010 | 275 | Travel - Meals & Enter | THE SLANTED DOOR | 54.21 | | 54.21 | | |
| 79010 | 275 | Travel - Meals & Enter | THE STAGE DELI | 12.88 | | 12.88 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | THE VANS RESTAURANT ON | 39.00 | | 39.00 | | |
| 79010 | 275 | Travel - Meals & Enter | THEDEPOT | 15.35 | | 15.35 | | |
| 79010 | 275 | Travel - Meals & Enter | THUNDER CANYON BREWERY | 38.94 | | 38.94 | | |
| 79010 | 275 | Travel - Meals & Enter | TIDEWATER LANDING | 64.99 | | 64.99 | | |
| 79010 | 275 | Travel - Meals & Enter | TILTED KILT OF ARI | 89.54 | | 89.54 | | |
| 79010 | 275 | Travel - Meals & Enter | TODAI RESTAURANT LAS V | 30.06 | | 30.06 | | |
| 79010 | 275 | Travel - Meals & Enter | TOMBOY'S #2 | 11.14 | | 11.14 | | |
| 79010 | 275 | Travel - Meals & Enter | TOMOKAZU JAPANESE CUIS | 18.18 | | 18.18 | | |
| 79010 | 275 | Travel - Meals & Enter | TONY ROMA'S | 28.00 | | 28.00 | | |
| 79010 | 275 | Travel - Meals & Enter | TONY ROMAS #606 | 80.03 | | 80.03 | | |
| 79010 | 275 | Travel - Meals & Enter | TORTILLA JO'S 00260323 | 20.81 | | 20.81 | | |
| 79010 | 275 | Travel - Meals & Enter | Transfer costs from O&M to capital | | 361.32 | (361.32) | | |
| 79010 | 275 | Travel - Meals & Enter | TRATTORIA PINA | 113.21 | | 113.21 | | |
| 79010 | 275 | Travel - Meals & Enter | TRATTORIA PINOCCHIO | 52.41 | | 52.41 | | |
| 79010 | 275 | Travel - Meals & Enter | TREASURE ISLAND - BUFF | 16.16 | | 16.16 | | |
| 79010 | 275 | Travel - Meals & Enter | TREASURE ISLAND LOBBY | 7.00 | | 7.00 | | |
| 79010 | 275 | Travel - Meals & Enter | TREASURE ISLAND PHO RE | 23.69 | | 23.69 | | |
| 79010 | 275 | Travel - Meals & Enter | TROPICANA - SAVANNA | 50.10 | | 50.10 | | |
| 79010 | 275 | Travel - Meals & Enter | TUCSON ELECTRIC PARK | 200.00 | | 200.00 | | |
| 79010 | 275 | Travel - Meals & Enter | TUCSON INTERNATION | 30.51 | | 30.51 | | |
| 79010 | 275 | Travel - Meals & Enter | TUCSON INTERNATIONAL A | 22.15 | | 22.15 | | |
| 79010 | 275 | Travel - Meals & Enter | TUCSON INT'L AIRPORT | 50.66 | | 50.66 | | |
| 79010 | 275 | Travel - Meals & Enter | UNCLE VITOS PIZZA | 39.98 | | 39.98 | | |
| 79010 | 275 | Travel - Meals & Enter | UNO CHICAGO BAR & GRIL | 27.74 | | 27.74 | | |
| 79010 | 275 | Travel - Meals & Enter | VENETO TRATTORIA | 29.05 | | 29.05 | | |
| 79010 | 275 | Travel - Meals & Enter | VILLA MARKET | 33.54 | | 33.54 | | |
| 79010 | 275 | Travel - Meals & Enter | VILLAGE INN RESTAURANT | 23.51 | | 23.51 | | |
| 79010 | 275 | Travel - Meals & Enter | VILLAGE TAVERN #7 | 164.36 | | 164.36 | | |
| 79010 | 275 | Travel - Meals & Enter | VINTAGE TERM A-DFW-AIR | 24.66 | | 24.66 | | |
| 79010 | 275 | Travel - Meals & Enter | VIROS ITALIAN BAKERY | 112.17 | | 112.17 | | |
| 79010 | 275 | Travel - Meals & Enter | VIVACE RESTAURANT | 158.31 | | 158.31 | | |
| 79010 | 275 | Travel - Meals & Enter | VOODOO DADDYS MAGIC KI | 26.18 | | 26.18 | | |
| 79010 | 275 | Travel - Meals & Enter | VSA/SBC PARK CONCESSIO | 61.25 | | 61.25 | | |
| 79010 | 275 | Travel - Meals & Enter | WAFFLE HOUSE #1380 | 18.28 | | 18.28 | | |
| 79010 | 275 | Travel - Meals & Enter | WALGREEN 00061Q39 | 5.36 | | 5.36 | | |
| 79010 | 275 | Travel - Meals & Enter | WAL-MART #1612 SE2 | 49.83 | | 49.83 | | |
| 79010 | 275 | Travel - Meals & Enter | WAL-MART #5031 SE2 | 14.01 | | 14.01 | | |
| 79010 | 275 | Travel - Meals & Enter | WARWICK DENVER REST | 80.67 | | 80.67 | | |
| 79010 | 275 | Travel - Meals & Enter | WARWICK HOTEL DENVER | 72.54 | | 72.54 | | |
| 79010 | 275 | Travel - Meals & Enter | WASATCH BREW PUB | 27.50 | | 27.50 | | |
| 79010 | 275 | Travel - Meals & Enter | WENDYS #2092 Q25 | 18.23 | | 18.23 | | |
| 79010 | 275 | Travel - Meals & Enter | WENDY'S #413 00004Q00 | 52.29 | | 52.29 | | |
| 79010 | 275 | Travel - Meals & Enter | WENDYS #8596 Q25 | 5.92 | | 5.92 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | WENDYS NO 413 Q50 | 13.45 | | 13.45 | | |
| 79010 | 275 | Travel - Meals & Enter | WESTIN HOTELS F B | 40.76 | | 40.76 | | |
| 79010 | 275 | Travel - Meals & Enter | WESTIN KIERLAND RESORT | 110.16 | | 110.16 | | |
| 79010 | 275 | Travel - Meals & Enter | WHATABURGER 598 Q26 | 30.40 | | 30.40 | | |
| 79010 | 275 | Travel - Meals & Enter | WHATABURGER 774 Q26 | 8.95 | | 8.95 | | |
| 79010 | 275 | Travel - Meals & Enter | WILDCAT HOUSE | 403.70 | | 403.70 | | |
| 79010 | 275 | Travel - Meals & Enter | WILDFLOWER | 57.27 | | 57.27 | | |
| 79010 | 275 | Travel - Meals & Enter | WINDEMERE HOTEL&CONF C | 7.97 | | 7.97 | | |
| 79010 | 275 | Travel - Meals & Enter | WM SUPERCENTER | 219.05 | | 219.05 | | |
| 79010 | 275 | Travel - Meals & Enter | WM SUPERCENTER SE2 | 475.96 | | 475.96 | | |
| 79010 | 275 | Travel - Meals & Enter | WYNN LAS VEGAS HOTEL | 11.00 | | 11.00 | | |
| 79010 | 275 | Travel - Meals & Enter | YANKEE PIER SFO | 79.44 | | 79.44 | | |
| 79010 | 275 | Travel - Meals & Enter | YEAGERS TAP HOUSE | 40.81 | | 40.81 | | |
| 79010 | 275 | Travel - Meals & Enter | YOKOHAMA ASIAN EXPRESS | 10.54 | | 10.54 | | |
| 79010 | 275 | Travel - Meals & Enter | YOYO SUSHI BAR & GRILL | 39.39 | | 39.39 | | |
| 79010 | 275 | Travel - Meals & Enter | Z TEJAS TEMPE #108 | 56.76 | | 56.76 | | |
| 79010 | 275 | Travel - Meals & Enter | ZACHARYS PIZZA | 98.58 | | 98.58 | | |
| 79010 | 275 | Travel - Meals & Enter | ZAYTINYA | 107.29 | | 107.29 | | |
| 79010 | 275 | Travel - Meals & Enter | ZEFFIRINOS | 45.60 | | 45.60 | | |
| 79010 | 275 | Travel - Meals & Enter | ZEMAMS | 64.88 | | 64.88 | | |
| 79010 | 275 | Travel - Meals & Enter | ZIVAZ | 78.99 | | 78.99 | | |
| 79010 | 275 | Travel - Meals & Enter | ZONA 78 | 48.81 | | 48.81 | | |
| 79010 | 275 | Travel - Meals & Enter | Z'TEJAS CHANDLER | 37.15 | | 37.15 | | |
| 79010 | 275 | Travel - Meals & Enter | | 1,032.02 | | 1,032.02 | SERVICE | 042406 103202 |
| 79010 | 275 | Travel - Meals & Enter | | 7,952.16 | | 7,952.16 | HOTEL & SUITES | 120806 795216 |
| 79010 | 275 | Travel - Meals & Enter | | 2,250.00 | | 2,250.00 | LLC | 050106 225000 |
| 79010 | 273 | Travel - Transportation | CAB-LIMO FARES QAE | 70.00 | | 70.00 | | |
| 79010 | 273 | Travel - Transportation | CHRISTOPHER ROBERT COR | 80.00 | | 80.00 | | |
| 79010 | 273 | Travel - Transportation | DENVER LUXERY LIMOUSIN | 85.00 | | 85.00 | | |
| 79010 | 273 | Travel - Transportation | MAGGIANO'S #8100000810 | 44.64 | | 44.64 | | |
| Sum | | | | 414,166.04 | 21,877.30 | **392,288.74** | | |

## TUCSON ELECTRIC POWER COMPANY

### DATA RESPONSE 1.20 (b): FERC 923 A&G Expense - Outside Services Employed

### TEST YEAR ENDING DECEMBER 31, 2006

Source: Transaction Detail - Co: 002, GL Period Name: %06, FERC: 0923

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 52020 | 156 | Contractor Services | LAMBCHOP STUDIOS | 135.00 | | 135.00 | | |
| 52020 | 157 | Outsourcing Services | JEWISH FAMILY | 80.00 | | 80.00 | | |
| 52020 | 157 | Outsourcing Services | MAGPIES GOURMET PIZZA | 95.06 | | 95.06 | | |
| 52020 | 157 | Outsourcing Services | RAPTOR RESEARCH FOUNDA | 822.50 | | 822.50 | | |
| 52020 | 157 | Outsourcing Services | ROSE HILLS-FLOWER SHOP | 135.31 | | 135.31 | | |
| 52020 | 157 | Outsourcing Services | | 300.00 | | 300.00 | BASEBALL CARDS ETC | 030106 30000 |
| 52020 | 157 | Outsourcing Services | | 5,000.00 | | 5,000.00 | UA FOUNDATION | 061206 500000 |
| 79200 | 271 | Training | ASU FOUNDATION | 200.00 | | 200.00 | | |
| 79200 | 271 | Training | FATRABBIT SERVICES | 185.00 | | 185.00 | | |
| **Total** | | | | 6,952.87 | 0.00 | **6,952.87** | | |

**TUCSON ELECTRIC POWER COMPANY**

**DATA RESPONSE 1.20 (c): FERC 930.1 A&G Expense - General Advertising Expense**

**TEST YEAR ENDING DECEMBER 31, 2006**

Source: Transaction Detail - Co: 002, GL Period Name: %06, FERC: 0930, Exp Types 153, 154, Plus all Exp Types for Task Number: CBU0063

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 52040 | 153 | Advertising | | 68,427.50 | | 68,427.50 | DIAMONDBACKS | D 12941 |
| 52040 | 153 | Advertising | | 68,427.50 | | 68,427.50 | DIAMONDBACKS | D 12941 |
| 52040 | 153 | Advertising | | 71,165.59 | | 71,165.59 | DIAMONDBACKS | IDBSP0000614 |
| 52040 | 153 | Advertising | | 71,165.59 | | 71,165.59 | DIAMONDBACKS | IDBSP0000614 |
| 52040 | 153 | Advertising | | 8,000.00 | | 8,000.00 | CONTRIBUTIONS | 120106 1600000 |
| 52040 | 153 | Advertising | | 300.00 | | 300.00 | PHOTOGRAPHY | 040606 30000 |
| 52040 | 153 | Advertising | | 12,500.00 | | 12,500.00 | KARTCHNER CAVERNS | 050406 2500000 |
| 52040 | 153 | Advertising | | 272.60 | | 272.60 | SPECIALTIES | 061571 |
| 52040 | 153 | Advertising | | 430.40 | | 430.40 | SPECIALTIES | 061408 |
| 52040 | 153 | Advertising | | 903.84 | | 903.84 | SPECIALTIES | 061384 |
| 52040 | 153 | Advertising | | 48.42 | | 48.42 | SPECIALTIES | 061195 |
| 52040 | 153 | Advertising | | 548.76 | | 548.76 | SPECIALTIES | 061012 |
| 52040 | 153 | Advertising | | 258.24 | | 258.24 | SPECIALTIES | 060758 |
| 52040 | 153 | Advertising | | 669.61 | | 669.61 | SPECIALTIES | 056105 |
| 52040 | 153 | Advertising | | 581.04 | | 581.04 | SPECIALTIES | 053695 |
| 52040 | 153 | Advertising | | 80.70 | | 80.70 | SPECIALTIES | 061192 |
| 52040 | 153 | Advertising | | 383.50 | | 383.50 | SPECIALTIES | 060251 |
| 52040 | 153 | Advertising | | 3,400.00 | | 3,400.00 | METROPOLITAN | 092006 340000 |
| 52040 | 153 | Advertising | | 20,000.00 | | 20,000.00 | METROPOLITAN | 033106 286079 |
| 52040 | 153 | Advertising | | 53,500.00 | | 53,500.00 | ARIZONA | 041706 10700000 |
| 52040 | 153 | Advertising | | 53,500.00 | | 53,500.00 | ARIZONA | 041706 10700000 |
| 52040 | 153 | Advertising Agencies | FINDERBINDER | 315.09 | | 315.09 | | |
| 52040 | 153 | Advertising Agencies | MINKUS ADVERTISING | 888.97 | | 888.97 | | |
| 52040 | 153 | Advertising Agencies | MINKUS ADVERTISING | 754.95 | | 754.95 | | |
| 52040 | 153 | Advertising Agencies | MINKUS ADVERTISING | 173.32 | | 173.32 | | |
| 52040 | 153 | Advertising Agencies | MINKUS ADVERTISING | 343.14 | | 343.14 | | |
| 52040 | 153 | Advertising Agencies | MINKUS ADVERTISING | 3,033.53 | | 3,033.53 | | |
| 52040 | 153 | Advertising Agencies | MINKUS ADVERTISING | 1,310.30 | | 1,310.30 | | |
| 52040 | 153 | Advertising Agencies | MINKUS ADVERTISING | 2,222.55 | | 2,222.55 | | |
| TOTAL | | | | 443,605.14 | 0.00 | **443,605.14** | | |

**TUCSON ELECTRIC POWER COMPANY**

**DATA RESPONSE 1.20 (d): FERC 930.2 A&G Expense - Misc. General Advertising Expense**

**TEST YEAR ENDING DECEMBER 31, 2006**

Source: Transaction Detail - Co: 002, GL Period Name: %06, FERC: 0930, excluding Exp Types 153, 154, excluding Task Number: CBU0063

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 51500 | 123 | Materials Purchased | LOWN'S COSTUMES | 110.00 | | 110.00 | | |
| 51500 | 123 | Materials Purchased | OSCO DRUG 9207 | 6.60 | | 6.60 | | |
| 51500 | 123 | Materials Purchased | PARTY CAROUSEL LLC | 161.21 | | 161.21 | | |
| 51500 | 123 | Materials Purchased | TARGET 00008540 | 202.07 | | 202.07 | | |
| 51500 | 123 | Materials Purchased | TARGET 00014399 | 62.19 | | 62.19 | | |
| 51500 | 123 | Materials Purchased | THINGS REMEMBERED 0329 | 110.08 | | 110.08 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AW | 16.21 | | 16.21 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AW | 67.57 | | 67.57 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AW | 18.92 | | 18.92 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AW | 16.22 | | 16.22 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AWAR | 34.97 | | 34.97 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AWAR | 34.97 | | 34.97 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AWAR | 34.97 | | 34.97 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AWAR | 204.44 | | 204.44 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AWAR | 18.83 | | 18.83 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AWAR | 54.05 | | 54.05 | | |
| 51500 | 123 | Materials Purchased | TULLER TROPHY'S & AWAR | 50.03 | | 50.03 | | |
| 51500 | 123 | Materials Purchased | WAL MART | 5.00 | | 5.00 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00002Q39 | 37.88 | | 37.88 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00022Q39 | 18.84 | | 18.84 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00058Q39 | 10.31 | | 10.31 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00062Q39 | 11.69 | | 11.69 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00064Q39 | 9.08 | | 9.08 | | |
| 51500 | 123 | Materials Purchased | WALGREEN 00073Q39 | 3.17 | | 3.17 | | |
| 51500 | 123 | Materials Purchased | WALL STREET GIFTS/COWS | 333.12 | | 333.12 | | |
| 51500 | 123 | Materials Purchased | WALL STREET GIFTS/COWS | 21.38 | | 21.38 | | |
| 51500 | 123 | Materials Purchased | | 1,314.60 | | 1,314.60 | COMMOTION STUDIO | 00008837 |
| 51500 | 123 | Materials Purchased | | 1,037.76 | | 1,037.76 | SPECIALTIES | 065398 |
| 51500 | 123 | Materials Purchased | | 831.40 | | 831.40 | SPECIALTIES | 065747 |
| 51500 | 123 | Materials Purchased | | 1,037.76 | | 1,037.76 | SPECIALTIES | 065102 |
| 51500 | 123 | Materials Purchased | | 173.32 | | 173.32 | SPECIALTIES | 064275 |
| 79010 | 282 | Meals & Ent - Discretionary | Gross Pay | 40.00 | | 40.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | Gross Pay | 24.00 | | 24.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | Gross Pay | 55.51 | | 55.51 | | |
| 79010 | 282 | Meals & Ent - Discretionary | Gross Pay | 59.00 | | 59.00 | | |
| 79010 | 282 | Meals & Ent - Discretionary | ARIZONA SONORA DESERT | 1,800.00 | | 1,800.00 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 282 | Meals & Ent - Discretionary | BRUEGGERS BAGEL BAKERY | 18.65 | | 18.65 | | |
| 79010 | 282 | Meals & Ent - Discretionary | BUSY B S BAKERY | 23.78 | | 23.78 | | |
| 79010 | 282 | Meals & Ent - Discretionary | EEGEE S #26 | 49.53 | | 49.53 | | |
| 79010 | 282 | Meals & Ent - Discretionary | EL MINUTO CAFE | 25.67 | | 25.67 | | |
| 79010 | 282 | Meals & Ent - Discretionary | LOS BETOS | 7.75 | | 7.75 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SAFEWAY STORE00002SC9 | 3.78 | | 3.78 | | |
| 79010 | 282 | Meals & Ent - Discretionary | SUBWAY | 16.44 | | 16.44 | | |
| 79020 | 251 | Member Dues - Corporate | | | 404.66 | (404.66) | | |
| 79020 | 251 | Member Dues - Corporate | AICPA *DUES ONLINE | 185.00 | | 185.00 | | |
| 79020 | 251 | Member Dues - Corporate | ALCPA *DUES LB | 530.00 | | 530.00 | | |
| 79020 | 251 | Member Dues - Corporate | AMERICAN WELDING SOCIE | 80.00 | | 80.00 | | |
| 79020 | 251 | Member Dues - Corporate | ASSOCTD BLDRS/CNTRC ED | 950.00 | | 950.00 | | |
| 79020 | 251 | Member Dues - Corporate | BBB OF TUCSON | 1,082.00 | | 1,082.00 | | |
| 79020 | 251 | Member Dues - Corporate | BRIGHT FUTURE BUSINESS | 450.00 | | 450.00 | | |
| 79020 | 251 | Member Dues - Corporate | NACM ARIZONA | 440.00 | | 440.00 | | |
| 79020 | 251 | Member Dues - Corporate | NATIONAL SAFETY COUNCI | 982.50 | | 982.50 | | |
| 79020 | 251 | Member Dues - Corporate | ORACLE APPLICATION CON | 595.00 | | 595.00 | | |
| 79020 | 251 | Member Dues - Corporate | PUBLIC RELATIONS SOCIE | 300.00 | | 300.00 | | |
| 79020 | 251 | Member Dues - Corporate | TUCSON METRO CHMBR CMM | 350.00 | | 350.00 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | | 176,282.64 | (176,282.64) | | |
| 79020 | 251 | Member Dues - Corporate | | 40,303.84 | | 40,303.84 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | | 11,632.00 | (11,632.00) | | |
| 79020 | 251 | Member Dues - Corporate | | 221,813.15 | | 221,813.15 | | |
| 79020 | 251 | Member Dues - Corporate | | | 267,067.00 | (267,067.00) | | |
| 79020 | 251 | Member Dues - Corporate | | 11,632.00 | | 11,632.00 | | |
| 79020 | 251 | Member Dues - Corporate | | 40,304.58 | | 40,304.58 | | |
| 79020 | 251 | Member Dues - Corporate | | 166.38 | | 166.38 | INC | 22536876 |
| 79020 | 251 | Member Dues - Corporate | | 267,067.00 | | 267,067.00 | INSTITUTE | 1-000038292A |
| 79020 | 251 | Member Dues - Corporate | | 28,019.00 | | 28,019.00 | INSTITUTE | 1-000038367D |
| 79020 | 251 | Member Dues - Corporate | | 25,217.10 | | 25,217.10 | INSTITUTE | 1-000038367C |
| 79020 | 251 | Member Dues - Corporate | | 25,217.10 | | 25,217.10 | INSTITUTE | 1-000038367 |
| 79020 | 251 | Member Dues - Corporate | | 20,691.00 | | 20,691.00 | INSTITUTE | 1-000045507 |
| 79020 | 251 | Member Dues - Corporate | | 28,019.00 | | 28,019.00 | INSTITUTE | 1-000038367B |
| 79020 | 251 | Member Dues - Corporate | | 1,790.00 | | 1,790.00 | ASSOCIATION OF | 12182218 |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79020 | 251 | Member Dues - Corporate | | 10,000.00 | | 10,000.00 | ASSOCIATES | 48776 |
| 79020 | 251 | Member Dues - Corporate | | 62.00 | | 62.00 | NOTARY BOND AGENCY | 042806 6200 |
| 79020 | 251 | Member Dues - Corporate | | 15,000.00 | | 15,000.00 | RMEL_ENDATED | 10891 |
| 79020 | 251 | Member Dues - Corporate | | 13,500.00 | | 13,500.00 | SCIENTECH LLC | IS-2007-778 |
| 79020 | 251 | Member Dues - Corporate | | 25.00 | | 25.00 | ARIZONA | 042806 2500 |
| 79020 | 251 | Member Dues - Corporate | | 12,000.00 | | 12,000.00 | LEADERSHIP COUNCIL | 692 |
| 79020 | 251 | Member Dues - Corporate | | 15,010.00 | | 15,010.00 | METROPOLITAN | 041106 286079 |
| 79020 | 251 | Member Dues - Corporate | | 62,500.00 | | 62,500.00 | ECONOMIC | 2006-11-TEP |
| 79020 | 251 | Member Dues - Corporate | | 62,500.00 | | 62,500.00 | ECONOMIC | 206-08-TEP |
| 79020 | 251 | Member Dues - Corporate | | 11,632.00 | | 11,632.00 | WEST ASSOCIATES | 012506 1163200 |
| 79020 | 251 | Member Dues - Corporate | | 216,587.22 | | 216,587.22 | COORDINATING | 40431 |
| 79020 | 251 | Member Dues - Corporate | | 1,800.00 | | 1,800.00 | WESTERN LAMPAC | 010506 180000 |
| 79200 | 299 | Miscellaneous | FTD*ROSES & MORE INC | 16.03 | | 16.03 | | |
| 79200 | 262 | Sponsorships | TUCSON HISPANIC CHAMBE | 40.00 | | 40.00 | | |
| 79200 | 262 | Sponsorships | | | 2,500.00 | (2,500.00) | | |
| 79200 | 262 | Sponsorships | | 2,500.00 | | 2,500.00 | | |
| 79200 | 262 | Sponsorships | | 2,500.00 | | 2,500.00 | COMMISSION | 012306 250000 |
| 79200 | 262 | Sponsorships | | 1,000.00 | | 1,000.00 | RESEARCH | 1092 |
| 79200 | 262 | Sponsorships | | | 210.00 | (210.00) | AYSO REGION 922 | 091505 21000 |
| 79200 | 262 | Sponsorships | | 3,250.00 | | 3,250.00 | COMMITTEE | 020606 325000 |
| 79010 | 272 | Travel | HYATT HOTELS DALLAS | 212.75 | | 212.75 | | |
| 79010 | 272 | Travel | LOWNS COSTUMES AND NOV | 825.00 | | 825.00 | | |
| 79010 | 272 | Travel | LOWNS COSTUMES AND NOV | 822.30 | | 822.30 | | |
| 79010 | 272 | Travel | MARRIOTT HOTELS UNIVER | 19.11 | | 19.11 | | |
| 79010 | 272 | Travel | ORANGE TREE GOLF RESOR | 218.39 | | 218.39 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #960 S9H | 53.91 | | 53.91 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #960 S9H | 25.08 | | 25.08 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #972 | 58.30 | | 58.30 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #972 | 9.98 | | 9.98 | | |
| 79010 | 275 | Travel - Meals & Enter | ALBERTSONS #972 S9H | 8.98 | | 8.98 | | |
| 79010 | 275 | Travel - Meals & Enter | APPLEBEE'S #603 | 41.12 | | 41.12 | | |
| 79010 | 275 | Travel - Meals & Enter | ARIZONA INN RESTAURANT | 37.42 | | 37.42 | | |
| 79010 | 275 | Travel - Meals & Enter | BAGGINS STORE #8 | 15.90 | | 15.90 | | |
| 79010 | 275 | Travel - Meals & Enter | BAGGINS STORE #8 | 18.93 | | 18.93 | | |
| 79010 | 275 | Travel - Meals & Enter | BAGGINS STORE #8 | 21.01 | | 21.01 | | |
| 79010 | 275 | Travel - Meals & Enter | BARRIO | 36.54 | | 36.54 | | |
| 79010 | 275 | Travel - Meals & Enter | BARRIO | 42.78 | | 42.78 | | |
| 79010 | 275 | Travel - Meals & Enter | BARRIO | 61.88 | | 61.88 | | |
| 79010 | 275 | Travel - Meals & Enter | BARRIO | 35.00 | | 35.00 | | |
| 79010 | 275 | Travel - Meals & Enter | BARRIO | 42.94 | | 42.94 | | |
| 79010 | 275 | Travel - Meals & Enter | BEER BOTTOM'S BISTRO | 21.00 | | 21.00 | | |
| 79010 | 275 | Travel - Meals & Enter | BIANCHIS ITALIAN | 28.01 | | 28.01 | | |
| 79010 | 275 | Travel - Meals & Enter | BRUEGGERS BAGEL BAKERY | 9.97 | | 9.97 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | BURGER KING #2845 Q07 | 9.81 | | 9.81 | | |
| 79010 | 275 | Travel - Meals & Enter | BUSY B S BAKERY | 9.51 | | 9.51 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFE A LA CART | 31.91 | | 31.91 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFE A LA CART | 24.54 | | 24.54 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFE A LA CART | 23.21 | | 23.21 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFFE MILANO LLC | 6.22 | | 6.22 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFFE MILANO LLC | 10.32 | | 10.32 | | |
| 79010 | 275 | Travel - Meals & Enter | CAFFE MILANO LLC | 59.70 | | 59.70 | | |
| 79010 | 275 | Travel - Meals & Enter | CHAFFINS FAMILY REST. | 18.34 | | 18.34 | | |
| 79010 | 275 | Travel - Meals & Enter | CHAFFINS FAMILY RESTAU | 35.74 | | 35.74 | | |
| 79010 | 275 | Travel - Meals & Enter | CHAFFINS FAMILY RESTAU | 16.89 | | 16.89 | | |
| 79010 | 275 | Travel - Meals & Enter | CHUYS MESQUITE BROILER | 39.77 | | 39.77 | | |
| 79010 | 275 | Travel - Meals & Enter | CHUYS MESQUITE BROILER | 29.29 | | 29.29 | | |
| 79010 | 275 | Travel - Meals & Enter | CLAIM JUMPER #35 | 42.92 | | 42.92 | | |
| 79010 | 275 | Travel - Meals & Enter | DOMINOES PIZZA #7627 | 228.37 | | 228.37 | | |
| 79010 | 275 | Travel - Meals & Enter | DOMINOES PIZZA #7634 | 63.35 | | 63.35 | | |
| 79010 | 275 | Travel - Meals & Enter | DOWNTOWN DELI | 139.94 | | 139.94 | | |
| 79010 | 275 | Travel - Meals & Enter | EEGEE S #19 | 13.47 | | 13.47 | | |
| 79010 | 275 | Travel - Meals & Enter | EEGEE S #20 | 31.79 | | 31.79 | | |
| 79010 | 275 | Travel - Meals & Enter | EEGEE S #26 | 10.35 | | 10.35 | | |
| 79010 | 275 | Travel - Meals & Enter | EEGEE S #27 | 92.59 | | 92.59 | | |
| 79010 | 275 | Travel - Meals & Enter | EL INDIO RESTURANT, IN | 20.84 | | 20.84 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MINUTO CAFE | 43.48 | | 43.48 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MINUTO CAFE | 27.66 | | 27.66 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MINUTO CAFE | 25.05 | | 25.05 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MINUTO CAFE | 22.93 | | 22.93 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MINUTO CAFE | 33.97 | | 33.97 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MINUTO CAFE | 36.21 | | 36.21 | | |
| 79010 | 275 | Travel - Meals & Enter | EL MINUTO CAFE | 20.67 | | 20.67 | | |
| 79010 | 275 | Travel - Meals & Enter | EL POLLO #3567 | 32.59 | | 32.59 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 52.80 | | 52.80 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 59.20 | | 59.20 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 14.62 | | 14.62 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 27.68 | | 27.68 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 47.46 | | 47.46 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 26.61 | | 26.61 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 36.01 | | 36.01 | | |
| 79010 | 275 | Travel - Meals & Enter | ELLE A WINE COUNTRY RE | 47.48 | | 47.48 | | |
| 79010 | 275 | Travel - Meals & Enter | ENOTECA PIZZARIA WINE | 21.27 | | 21.27 | | |
| 79010 | 275 | Travel - Meals & Enter | ENOTECA PIZZARIA WINE | 11.58 | | 11.58 | | |
| 79010 | 275 | Travel - Meals & Enter | ENOTECA PIZZARIA WINE | 27.90 | | 27.90 | | |
| 79010 | 275 | Travel - Meals & Enter | ENOTECA PIZZARIA WINE | 17.65 | | 17.65 | | |
| 79010 | 275 | Travel - Meals & Enter | FAMOUS DAVE'S BBQ | 62.65 | | 62.65 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | FAMOUS SAMS #28 | 45.59 | | 45.59 | | |
| 79010 | 275 | Travel - Meals & Enter | FOOD CITY #133 | 70.69 | | 70.69 | | |
| 79010 | 275 | Travel - Meals & Enter | FOOD CITY #147 ST3 | 12.96 | | 12.96 | | |
| 79010 | 275 | Travel - Meals & Enter | FOOD CITY# 136 ST3 | 33.73 | | 33.73 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #017 SXN | 56.62 | | 56.62 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #036 SXN | 105.31 | | 105.31 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #036 SXN | 17.28 | | 17.28 | | |
| 79010 | 275 | Travel - Meals & Enter | FRYS-FOOD-DRG #036 SXN | 19.12 | | 19.12 | | |
| 79010 | 275 | Travel - Meals & Enter | HMSHOST-DFW-AIRPT #007 | 12.81 | | 12.81 | | |
| 79010 | 275 | Travel - Meals & Enter | IHOP #1525 04315255 | 19.90 | | 19.90 | | |
| 79010 | 275 | Travel - Meals & Enter | JADE GARDEN RESTAURANT | 77.28 | | 77.28 | | |
| 79010 | 275 | Travel - Meals & Enter | KFC 29000Q30 | 27.22 | | 27.22 | | |
| 79010 | 275 | Travel - Meals & Enter | LEVY GRP SALE 90085002 | 1,726.00 | | 1,726.00 | | |
| 79010 | 275 | Travel - Meals & Enter | LIGHTNING RIDGE CAFE | 104.91 | | 104.91 | | |
| 79010 | 275 | Travel - Meals & Enter | LIGHTNING RIDGE CAFE | 14.53 | | 14.53 | | |
| 79010 | 275 | Travel - Meals & Enter | LITTLE MEXICO RESTAURA | 18.21 | | 18.21 | | |
| 79010 | 275 | Travel - Meals & Enter | LITTLE MEXICO STEAKHOU | 38.12 | | 38.12 | | |
| 79010 | 275 | Travel - Meals & Enter | LOS BETOS | 14.85 | | 14.85 | | |
| 79010 | 275 | Travel - Meals & Enter | LOS BETOS | 20.20 | | 20.20 | | |
| 79010 | 275 | Travel - Meals & Enter | LOS BETOS | 27.21 | | 27.21 | | |
| 79010 | 275 | Travel - Meals & Enter | LOS BETOS MEXICAN FOOD | 16.12 | | 16.12 | | |
| 79010 | 275 | Travel - Meals & Enter | LUCKY WISHBONE #1 | 43.58 | | 43.58 | | |
| 79010 | 275 | Travel - Meals & Enter | LUCKY WISHBONE NO | 38.27 | | 38.27 | | |
| 79010 | 275 | Travel - Meals & Enter | MAGPIES GOURMET PIZZA | 17.89 | | 17.89 | | |
| 79010 | 275 | Travel - Meals & Enter | MAMA'S FAMOUS # 2 | 45.59 | | 45.59 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD'S F1034 Q17 | 14.09 | | 14.09 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD S F18787 Q17 | 12.30 | | 12.30 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD'S M7673 OFQ17 | 19.09 | | 19.09 | | |
| 79010 | 275 | Travel - Meals & Enter | MCDONALD'S M7673 OFQ17 | 18.60 | | 18.60 | | |
| 79010 | 275 | Travel - Meals & Enter | MICHAS | 26.50 | | 26.50 | | |
| 79010 | 275 | Travel - Meals & Enter | MR. C'S RESTAURANT | 51.87 | | 51.87 | | |
| 79010 | 275 | Travel - Meals & Enter | NADINES PASTRY SHOPPE | 61.10 | | 61.10 | | |
| 79010 | 275 | Travel - Meals & Enter | NADINES PASTRY SHOPPE | 8.59 | | 8.59 | | |
| 79010 | 275 | Travel - Meals & Enter | NADINES PASTRY SHOPPE | 42.93 | | 42.93 | | |
| 79010 | 275 | Travel - Meals & Enter | NEW DRAGON VIEW | 23.01 | | 23.01 | | |
| 79010 | 275 | Travel - Meals & Enter | OLD FATHER INN | 53.65 | | 53.65 | | |
| 79010 | 275 | Travel - Meals & Enter | OLD PUEBLO GRILLE | 24.45 | | 24.45 | | |
| 79010 | 275 | Travel - Meals & Enter | OLD PUEBLO GRILLE | 35.05 | | 35.05 | | |
| 79010 | 275 | Travel - Meals & Enter | OLD PUEBLO GRILLE | 11.74 | | 11.74 | | |
| 79010 | 275 | Travel - Meals & Enter | PARADISE BAKERY | 48.65 | | 48.65 | | |
| 79010 | 275 | Travel - Meals & Enter | PETER PIPER PIZZA STOR | 59.56 | | 59.56 | | |
| 79010 | 275 | Travel - Meals & Enter | R AND R PIZZA EXPRESS | 44.14 | | 44.14 | | |
| 79010 | 275 | Travel - Meals & Enter | RIGO S RESTAURANT | 64.52 | | 64.52 | | |

| Acct | Exp Type | Exp Type Description | Pa Expenditure Comment | DR | CR | Net Amount | Vendor Name | Invoice Number |
|---|---|---|---|---|---|---|---|---|
| 79010 | 275 | Travel - Meals & Enter | RIGO S RESTAURANT | 21.18 | | 21.18 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00002550 | 19.52 | | 19.52 | | |
| 79010 | 275 | Travel - Meals & Enter | SAFEWAY STORE00020SC9 | 4.50 | | 4.50 | | |
| 79010 | 275 | Travel - Meals & Enter | SAM HUGHES PLACE | 49.55 | | 49.55 | | |
| 79010 | 275 | Travel - Meals & Enter | SONIC DRIVE IN #399Q63 | 24.65 | | 24.65 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY | 8.37 | | 8.37 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY # 1845 | 4.73 | | 4.73 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY 1840 00018Q16 | 95.64 | | 95.64 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY 1840 00018Q16 | 133.20 | | 133.20 | | |
| 79010 | 275 | Travel - Meals & Enter | SUBWAY 25702 | 15.60 | | 15.60 | | |
| 79010 | 275 | Travel - Meals & Enter | TANIA 33 | 42.63 | | 42.63 | | |
| 79010 | 275 | Travel - Meals & Enter | TANIA 33 | 34.33 | | 34.33 | | |
| 79010 | 275 | Travel - Meals & Enter | TANIA 33 | 24.11 | | 24.11 | | |
| 79010 | 275 | Travel - Meals & Enter | THE GOOD EGG WILLIAMS | 69.51 | | 69.51 | | |
| 79010 | 275 | Travel - Meals & Enter | THE GOOD EGG WILLIAMS | 42.48 | | 42.48 | | |
| 79010 | 275 | Travel - Meals & Enter | VIVA BURRITO COMPA QAE | 35.77 | | 35.77 | | |
| 79010 | 275 | Travel - Meals & Enter | VIVA BURRITO COMPA QAE | 24.23 | | 24.23 | | |
| 79010 | 275 | Travel - Meals & Enter | VIVA BURRITO COMPA QAE | 11.32 | | 11.32 | | |
| 79010 | 275 | Travel - Meals & Enter | VIVA BURRITO COMPA QAE | 5.29 | | 5.29 | | |
| 79010 | 275 | Travel - Meals & Enter | VIVA BURRITO COMPA QAE | 11.89 | | 11.89 | | |
| 79010 | 275 | Travel - Meals & Enter | VIVACE RESTAURANT | 35.15 | | 35.15 | | |
| 79010 | 275 | Travel - Meals & Enter | WHATABURGER 552 | 7.76 | | 7.76 | | |
| 79010 | 275 | Travel - Meals & Enter | WIE NERSCHNITZEL #678 | 20.69 | | 20.69 | | |
| 79010 | 275 | Travel - Meals & Enter | WILDCAT HOUSE | 42.34 | | 42.34 | | |
| 79010 | 275 | Travel - Meals & Enter | WILDCAT HOUSE | 30.41 | | 30.41 | | |
| **TOTAL** | | | | 1,525,400.19 | 458,096.30 | **1,067,303.89** | | |

# EXHIBIT B

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006



**EXHIBIT B**
**TEST YEAR PLANT SCHEDULES - CONT'D**
**YEAR ENDED DECEMBER 31, 2004**

| LINE NO. | ACCT NO. | ACCOUNT NAME | (A) AUTH'ZD DEP. RATE | (B) BEGINNING PLANT BALANCE | (C) BEGINNING ACC. DEP. BALANCE | (D) PLANT ADDITIONS | (E) PLANT RETIREM'TS | (F) PLANT ADJUSTM'TS | (G) PLANT TRANSFERS | (H) TOTAL PLANT VALUE | (I) ACCURAL DEPRECIATION | (J) ACCUMULATED DEPRECIATION | (K) NET PLANT VALUE | (L) ACC. DEP. COMPANY WORKPAPERS | (M) ACC. DEP. DIFFERENCE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **INTANGIBLE PLANT** | | | | | | | | | | | | | |
| 1 | 301 | Organization | 0.00% | $ 29,362 | $ - | $ - | $ - | $ - | $ - | $ 29,362 | $ - | $ - | $ 29,362 | | |
| 2 | 302 | Franchises and Consents | 0.00% | 147,884 | - | - | - | - | - | 147,884 | - | - | 147,884 | | |
| 3 | 303 | Miscellaneous Intangible Plant | 0.00% | 48,615,887 | - | 7,748,769 | (750,000) | - | - | 55,614,656 | - | 750,000 | 56,364,656 | | |
| 4 | | TOTAL Intangible Plant (Sum L's 1, 2, 3) | | $ 48,793,133 | $ - | $ 7,748,769 | $ (750,000) | $ - | $ - | $ 55,791,902 | $ - | $ 750,000 | $ 56,541,902 | $ - | $ 750,000 |
| | | **PRODUCTION PLANT** | | | | | | | | | | | | | |
| | | Steam Production Plant | | | | | | | | | | | | | |
| 5 | 310 | Land and Land Rights | 1.99% | $ 5,878,540 | $ (1,633,030) | $ - | $ - | $ - | $ - | $ 5,878,540 | $ (116,983) | $ (1,750,013) | $ 4,128,527 | | |
| 6 | 311 | Structures and Improvements | 3.00% | 118,388,614 | (41,594,244) | 1,048,680 | (13,834) | - | - | 119,423,460 | (3,567,181) | (45,147,591) | 74,275,869 | | |
| 7 | 312 | Boiler Plant Equipment | 3.29% | 664,053,514 | (316,829,721) | 12,076,681 | (2,634,874) | - | - | 673,495,321 | (22,002,678) | (336,197,525) | 337,297,796 | | |
| 8 | 313 | Engines and Engine-Driven Generators | 0.00% | - | - | - | - | - | - | - | - | - | - | | |
| 9 | 314 | Turbogenerator Units | 2.88% | 213,798,200 | (105,525,904) | 9,346,211 | (624,810) | - | - | 222,519,601 | (6,282,976) | (111,184,070) | 111,335,531 | | |
| 10 | 315 | Accessory Electric Equipment | 2.68% | 80,972,752 | (35,937,406) | 133,167 | (9,576) | - | - | 81,096,343 | (2,171,726) | (38,099,556) | 42,996,787 | | |
| 11 | 316 | Misc. Power Plant Equipment | 4.05% | 17,265,227 | (9,181,774) | 1,364,565 | (69,219) | - | - | 18,560,573 | (725,472) | (9,838,027) | 8,722,546 | | |
| 12 | 317 | Asset Retm't Costs for Steam Production | 2.43% | 69,981 | (53,568) | 22,787 | - | - | - | 92,768 | (1,977) | (55,545) | 37,223 | | |
| 13 | 114 | San Juan Acquisition Adjustment | 3.73% | 3,124,669 | (2,716,293) | - | - | - | - | 3,124,669 | (116,655) | (2,832,948) | 291,721 | | |
| 14 | | TOTAL Steam Plant (Sum L's 5 Thru 13) | | $1,103,551,497 | $ (513,471,940) | $ 23,992,091 | $ (3,352,313) | $ - | $ - | $ 1,124,191,275 | $ (34,985,649) | $ (545,105,276) | $ 579,085,999 | $ (533,775,374) | $ (11,329,902) |
| | | Other Production Plant | | | | | | | | | | | | | |
| 15 | 340 | Land and Land Rights | 0.00% | $ 401,628 | $ - | $ - | $ - | $ - | $ - | $ 401,628 | $ - | $ - | $ 401,628 | | |
| 16 | 341 | Structures and Improvements | 2.02% | 1,219,747 | (538,047) | - | - | - | - | 1,219,747 | (24,639) | (562,686) | 657,061 | | |
| 17 | 342 | Fuel Holders, Products, and Accessories | 2.35% | 1,156,176 | (114,044) | 8,719 | - | - | - | 1,164,895 | (27,273) | (141,317) | 1,023,578 | | |
| 18 | 343 | Prime Movers | 1.48% | 354,047 | (281,725) | - | - | - | - | 354,047 | (5,240) | (286,965) | 67,082 | | |
| 19 | 344 | Generators | 1.81% | 75,805,654 | (16,788,626) | - | - | (3,862,639) | - | 71,943,015 | (1,337,125) | (18,125,751) | 53,817,264 | | |
| 20 | 345 | Accessory Electric Equipment | 1.85% | 4,125,787 | (1,874,255) | 349,430 | - | - | - | 4,475,217 | (79,559) | (1,953,814) | 2,521,403 | | |
| 21 | 346 | Misc. Power Plant Equipment | 2.72% | 682,690 | (439,070) | 355,620 | - | - | - | 1,038,310 | (23,406) | (462,476) | 575,834 | | |
| 22 | | TOTAL Other Plant (Sum L's 15 Thru 21) | | $ 83,745,729 | $ (20,035,767) | $ 713,769 | $ - | $ (3,862,639) | $ - | $ 80,596,859 | $ (1,497,242) | $ (21,533,009) | $ 59,063,850 | $ (21,044,336) | $ (488,673) |
| 23 | | TOTAL Production Plant (Sum L's 14 & 22) | | $1,187,297,226 | $ (533,507,707) | $ 24,705,860 | $ (3,352,313) | $ (3,862,639) | $ - | $ 1,204,788,134 | $ (36,482,891) | $ (566,638,285) | $ 638,149,849 | $ (554,819,710) | $ (11,818,575) |
| | | **TRANSMISSION PLANT** | | | | | | | | | | | | | |
| | | Transmission Non-EHV (138 KV & Below) | | | | | | | | | | | | | |
| 24 | 350 | Land and Land Rights | 2.25% | $ 10,926,112 | $ (11,350,702) | $ - | $ - | $ - | $ - | $ 10,926,112 | $ (245,838) | $ (11,596,540) | $ (670,428) | | |
| 25 | 352 | Structures and Improvements | 2.44% | 6,680,804 | (8,210,209) | 1,283,968 | - | - | - | 7,964,772 | (178,676) | (8,388,885) | (424,113) | | |
| 26 | 353 | Station Equipment | 3.52% | 117,834,991 | (112,620,578) | 1,986,425 | (1,574,279) | - | - | 118,247,137 | (4,155,045) | (115,201,344) | 3,045,793 | | |
| 27 | 354 | Towers and Fixtures | 3.53% | 9,811,270 | (104,792,995) | - | - | - | - | 9,811,270 | (346,338) | (105,139,333) | (95,328,063) | | |
| 28 | 355 | Poles and Fixtures | 4.54% | 16,651,993 | (12,268,561) | 1,719,967 | (81,714) | - | - | 18,290,246 | (793,189) | (12,980,036) | 5,310,210 | | |
| 29 | 356 | Overhead Conductors and Devices | 3.33% | 15,905,453 | (53,034,553) | 80,423 | (1,015,917) | - | - | 14,969,959 | (514,076) | (52,532,712) | (37,562,753) | | |
| 30 | | TOTAL Transmission NOn-EHV (Sum L's 24 Thru 29) | | $ 177,810,623 | $ (302,277,598) | $ 5,070,783 | $ (2,671,910) | $ - | $ - | $ 180,209,496 | $ (6,233,161) | $ (305,838,849) | $ (125,629,353) | | |

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

Cost of Service
Plant Schedules
Pages 1 & 2 of 6

## EXHIBIT B
## TEST YEAR PLANT SCHEDULES - CONT'D
## YEAR ENDED DECEMBER 31, 2004

| LINE NO. | ACCT NO. | ACCOUNT NAME | (A) AUTH'ZD DEP. RATE | (B) BEGINNING PLANT BALANCE | (C) BEGINNING ACC. DEP. BALANCE | (D) PLANT ADDITIONS | (E) PLANT RETIREM'TS | (F) PLANT ADJUSTM'TS | (G) PLANT TRANSFERS | (H) TOTAL PLANT VALUE | (I) ACCURAL DEPRECIATION | (J) ACCUMULATED DEPRECIATION | (K) NET PLANT VALUE | (L) ACC. DEP. COMPANY WORKPAPERS | (M) ACC. DEP. DIFFERENCE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Transmission EHV (345 KV & Above) | | | | | | | | | | | | | |
| 31 | 350 | Land and Land Rights | 2.25% | $ 15,148,405 | $ - | $ - | $ - | $ - | $ - | $ 15,148,405 | $ (340,839) | $ (340,839) | $ 14,807,566 | | |
| 32 | 352 | Structures and Improvements | 2.44% | 9,178,154 | - | 892,103 | - | - | - | 10,070,257 | (234,831) | (234,831) | 9,835,426 | | |
| 33 | 353 | Station Equipment | 3.52% | 110,474,060 | - | 4,719,833 | (36,397) | - | - | 115,157,496 | (3,971,115) | (3,934,718) | 111,222,778 | | |
| 34 | 354 | Towers and Fixtures | 3.53% | 145,725,013 | - | - | - | (2,540) | - | 145,722,473 | (5,144,048) | (5,144,048) | 140,578,425 | | |
| 35 | 355 | Poles and Fixtures | 4.54% | 1,341,221 | - | - | - | - | - | 1,341,221 | (60,891) | (60,891) | 1,280,330 | | |
| 36 | 356 | Overhead Conductors and Devices | 3.33% | 66,328,769 | - | - | - | (1,765) | - | 66,325,004 | (2,208,652) | (2,208,652) | 64,116,352 | | |
| 37 | 359 | Roads & Trails | 2.00% | 4,485,615 | (2,673,027) | 160,601 | - | - | - | 4,646,216 | (91,318) | (2,764,345) | 1,881,871 | | |
| 38 | | TOTAL Transmission EHV (Sum L's 31 Thru 36) | | $ 352,679,237 | $ (2,673,027) | $ 5,772,537 | $ (36,397) | $ (4,305) | $ - | $ 358,411,072 | $ (12,051,695) | $ (14,688,325) | $ 343,722,747 | | |
| 39 | | TOTAL Transmission Plant (Sum L's 30 & 37) | | $ 530,489,860 | $ (304,950,625) | $ 10,843,320 | $ (2,708,307) | $ (4,305) | $ - | $ 538,620,568 | $ (18,284,856) | $ (320,527,174) | $ 218,093,394 | $ (320,865,012) | $ 337,838 |
| | | DISTRIBUTION PLANT | | | | | | | | | | | | | |
| 40 | 360 | Land and Land Rights | 2.22% | $ 8,761,076 | $ (2,289,324) | $ - | $ - | $ - | $ - | $ 8,761,076 | $ (194,496) | $ (2,483,820) | $ 6,277,256 | | |
| 41 | 361 | Structures and Improvements | 2.44% | 4,142,199 | (1,295,749) | 815,814 | - | - | - | 4,958,013 | (111,023) | (1,406,772) | 3,551,241 | | |
| 42 | 362 | Station Equipment | 4.25% | 74,866,825 | (51,613,094) | 11,658,550 | - | - | - | 86,525,375 | (3,429,584) | (55,042,678) | 31,482,697 | | |
| 43 | 364 | Poles, Towers, and Fixtures | 5.48% | 91,517,511 | (63,729,094) | 8,931,864 | (184,715) | - | - | 100,264,660 | (5,254,831) | (68,799,210) | 31,465,450 | | |
| 44 | 365 | Overhead Conductors and Devices | 3.66% | 95,065,115 | (48,553,886) | 3,258,292 | (153,926) | - | - | 98,169,481 | (3,536,193) | (51,936,153) | 46,233,328 | | |
| 45 | 366 | Underground Conduit | 2.33% | 45,860,914 | (12,113,190) | 3,668,651 | (40,394) | - | - | 49,489,171 | (1,110,828) | (13,183,624) | 36,305,547 | | |
| 46 | 367 | Underground Conductors and Devices | 1.63% | 175,621,937 | (40,117,178) | 9,039,591 | (325,727) | - | - | 184,335,801 | (2,933,656) | (42,725,107) | 141,610,694 | | |
| 47 | 368 | Line Transformers | 3.38% | 163,480,374 | (63,256,698) | 13,595,044 | (1,856,318) | - | - | 175,219,100 | (5,724,021) | (67,124,399) | 108,094,701 | | |
| 48 | 369 | Services | 3.83% | 76,009,724 | (36,418,284) | 3,456,146 | (55,014) | - | - | 79,410,856 | (2,976,304) | (39,339,574) | 40,071,282 | | |
| 49 | 370 | Meters | 3.79% | 36,655,848 | (19,159,868) | 1,641,919 | (10,734,023) | - | - | 27,763,744 | (1,224,541) | (9,650,386) | 18,113,358 | | |
| 50 | 371 | Installations on Customer Premises | 0.00% | - | - | - | - | - | - | - | - | - | - | | |
| 51 | 373 | Street Lighting and Signal Systems | 4.46% | 8,142,648 | (4,729,768) | 546,135 | (17,274) | - | - | 8,671,507 | (374,956) | (5,087,450) | 3,584,057 | | |
| 52 | 374 | Asset Retirement Obligation | | - | - | - | - | - | - | - | - | - | - | | |
| 53 | | TOTAL Distribution Plant (Sum L's 39 Thru 51) | | $ 780,324,169 | $ (343,276,131) | $ 56,612,006 | $ (13,367,391) | $ - | $ - | $ 823,568,784 | $ (26,870,433) | $ (356,779,173) | $ 466,789,611 | $ (357,710,354) | $ 931,181 |
| | | GENERAL PLANT | | | | | | | | | | | | | |
| 54 | 389 | Land and Land Rights | 0.00% | $ 302,740 | $ - | $ - | $ - | $ - | $ - | $ 302,740 | $ - | $ - | $ 302,740 | | |
| 55 | 390 | Structures and Improvements | 3.38% | 28,272,387 | (7,992,518) | 3,619,230 | (214,582) | - | - | 31,677,035 | (1,013,145) | (8,791,081) | 22,885,954 | | |
| 56 | 391 | Office Furniture and Equipment | 13.38% | 21,573,813 | (11,885,733) | 4,081,060 | (1,824) | - | - | 25,653,049 | (3,159,477) | (15,043,386) | 10,609,663 | | |
| 57 | 392 | Transportation Equipment | 4.72% | 27,621,652 | (13,553,632) | 4,003,539 | (1,102,653) | - | - | 30,522,538 | (1,372,203) | (13,823,182) | 16,699,356 | | |
| 58 | 393 | Stores Equipment | 6.67% | 814,671 | (719,914) | 84,654 | | - | - | 899,325 | (57,162) | (777,076) | 122,249 | | |
| 59 | 394 | Tools, Shop and Garage Equipment | 5.88% | 8,093,684 | (4,056,462) | 443,717 | - | - | - | 8,537,401 | (488,954) | (4,545,416) | 3,991,985 | | |
| 60 | 395 | Laboratory Equipment | 5.88% | 4,948,174 | (2,290,856) | 87,905 | (133,533) | - | - | 4,902,546 | (289,611) | (2,446,934) | 2,455,612 | | |
| 61 | 396 | Power Operated Equipment | 3.33% | 8,527,364 | (925,562) | 110,988 | - | - | - | 8,638,352 | (285,809) | (1,211,371) | 7,426,981 | | |
| 62 | 397 | Communication Equipment | 6.67% | 31,405,548 | (21,931,201) | 2,088,891 | - | - | - | 33,494,439 | (2,164,415) | (24,095,616) | 9,398,823 | | |
| 63 | 398 | Miscellaneous Equipment | 5.00% | 2,038,957 | (873,767) | - | - | - | - | 2,038,957 | (101,948) | (975,715) | 1,063,242 | | |
| 64 | | TOTAL General Plant (Sum L's 53 Thru 62) | | $ 133,598,990 | $ (64,229,645) | $ 14,519,984 | $ (1,452,592) | $ - | $ - | $ 146,666,382 | $ (8,932,724) | $ (71,709,777) | $ 74,956,605 | $ (72,570,401) | $ 860,624 |
| 65 | | TOTAL PLANT(Sum L's 4, 23, 38, 52 & 63) | | $2,680,503,378 | $ (1,245,964,108) | $ 114,429,939 | $ (21,630,603) | $ (3,866,944) | $ - | $ 2,769,435,770 | $ (90,570,905) | $ (1,314,904,410) | $ 1,454,531,360 | $ (1,305,965,477) | $ (8,938,933) |
| 66 | | | | Company Workpapers | $ (1,243,247,815) | | | | | | Company Workpapers | $ (1,305,965,478) | | | |
| 67 | | | | San Juan Acquisition Adjustment Line 13 | (2,716,293) | | | | | | | | | | |
| 68 | | | | Sum Line 66 + Line 67 | $ (1,245,964,108) | | | | | | Difference | $ (8,938,932) | | | |

**EXHIBIT B**
**TEST YEAR PLANT SCHEDULES - CONT'D**
**YEAR ENDED DECEMBER 31, 2005**

| LINE NO. | ACCT NO. | ACCOUNT NAME | (A) PLANT ADDITIONS | (B) PLANT RETIREM'TS | (C) PLANT ADJUSTM'TS | (D) PLANT TRANSFERS | (E) TOTAL PLANT VALUE | (F) ACCURAL DEPREC'N | (G) ACCUM'D DEPREC'N | (H) NET PLANT VALUE | (I) ACC. DEP. COMPANY WORKPAPERS | (J) ACC. DEP. DIFFERENCE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **INTANGIBLE PLANT** | | | | | | | | | | |
| 1 | 301 | Organization | $ - | $ - | $ - | $ - | $ 29,362 | $ - | $ - | $ 29,362 | | |
| 2 | 302 | Franchises and Consents | - | - | - | - | 147,884 | - | - | 147,884 | | |
| 3 | 303 | Miscellaneous Intangible Plant | 1,875,684 | - | 750,000 | - | 58,240,340 | - | - | 58,240,340 | | |
| 4 | | TOTAL Intangible Plant (Sum L's 1, 2, 3) | $ 1,875,684 | $ - | $ 750,000 | $ - | $ 58,417,586 | $ - | $ - | $ 58,417,586 | $ - | $ - |
| | | **PRODUCTION PLANT** | | | | | | | | | | |
| | | Steam Production Plant | | | | | | | | | | |
| 5 | 310 | Land and Land Rights | $ - | $ - | $ - | $ - | $ 5,878,540 | $ (116,983) | $ (1,866,996) | $ 4,011,544 | | |
| 6 | 311 | Structures and Improvements | 1,867,049 | (313,335) | - | - | 120,977,174 | (3,606,010) | (48,440,266) | 72,536,908 | | |
| 7 | 312 | Boiler Plant Equipment | 28,971,548 | (10,683,041) | - | - | 691,783,828 | (22,458,842) | (347,973,326) | 343,810,502 | | |
| 8 | 313 | Engines and Engine-Driven Generators | - | - | - | - | - | - | - | - | | |
| 9 | 314 | Turbogenerator Units | 8,666,638 | (3,457,961) | - | - | 227,728,278 | (6,483,569) | (114,209,679) | 113,518,599 | | |
| 10 | 315 | Accessory Electric Equipment | 1,336,734 | (441,393) | - | - | 81,991,684 | (2,185,380) | (39,843,542) | 42,148,142 | | |
| 11 | 316 | Misc. Power Plant Equipment | 1,023,790 | (105,949) | - | - | 19,478,414 | (770,289) | (10,502,368) | 8,976,046 | | |
| 12 | 317 | Asset Retm't Costs for Steam Production | 274,147 | - | - | - | 366,915 | (5,585) | (61,131) | 305,784 | | |
| 13 | 114 | San Juan Acquisition Adjustment | - | - | - | - | 3,124,669 | (116,655) | (2,949,603) | 175,066 | | |
| 14 | | TOTAL Steam Plant (Sum L's 5 Thru 13) | $ 42,139,906 | $ (15,001,679) | $ - | $ - | $ 1,151,329,502 | $ (35,743,313) | $ (565,846,911) | $ 585,482,591 | $ (536,883,398) | $ (28,963,513) |
| | | Other Production Plant | | | | | | | | | | |
| 15 | 340 | Land and Land Rights | $ - | $ - | $ - | $ - | $ 401,628 | $ - | $ - | $ 401,628 | | |
| 16 | 341 | Structures and Improvements | 140,347 | - | - | - | 1,360,094 | (26,056) | (588,742) | 771,352 | | |
| 17 | 342 | Fuel Holders, Products, and Accessories | - | - | - | - | 1,164,895 | (27,375) | (168,692) | 996,203 | | |
| 18 | 343 | Prime Movers | - | - | - | - | 354,047 | (5,240) | (292,205) | 61,842 | | |
| 19 | 344 | Generators | 346,938 | - | - | - | 72,289,953 | (1,305,308) | (19,431,060) | 52,858,893 | | |
| 20 | 345 | Accessory Electric Equipment | - | - | - | - | 4,475,217 | (82,792) | (2,036,606) | 2,438,611 | | |
| 21 | 346 | Misc. Power Plant Equipment | - | - | - | - | 1,038,310 | (28,242) | (490,718) | 547,592 | | |
| 22 | | TOTAL Other Plant (Sum L's 15 Thru 21) | $ 487,285 | $ - | $ - | $ - | $ 81,084,144 | $ (1,475,013) | $ (23,008,022) | $ 58,076,122 | $ (21,924,580) | $ (1,083,442) |
| 23 | | TOTAL Production Plant (Sum L's 14 & 22) | $ 42,627,191 | $ (15,001,679) | $ - | $ - | $ 1,232,413,646 | $ (37,218,326) | $ (588,854,933) | $ 643,558,713 | $ (558,807,978) | $ (30,046,955) |
| | | **TRANSMISSION PLANT** | | | | | | | | | | |
| | | Transmission Non-EHV (138 KV & Below) | | | | | | | | | | |
| 24 | 350 | Land and Land Rights | $ - | $ (36,251) | $ - | $ - | $ 10,889,861 | $ (245,430) | $ (11,805,718) | $ (915,857) | | |
| 25 | 352 | Structures and Improvements | - | - | (326,793) | - | 7,637,979 | (190,354) | (8,579,239) | (941,260) | | |
| 26 | 353 | Station Equipment | 671,767 | - | 1,475,568 | - | 120,394,472 | (4,200,092) | (119,401,437) | 993,035 | | |
| 27 | 354 | Towers and Fixtures | - | - | - | - | 9,811,270 | (346,338) | (105,485,671) | (95,674,401) | | |
| 28 | 355 | Poles and Fixtures | 367,206 | - | 2,939 | - | 18,660,391 | (838,779) | (13,818,815) | 4,841,576 | | |
| 29 | 356 | Overhead Conductors and Devices | 1,265,515 | - | 784,570 | - | 17,020,044 | (532,634) | (53,065,345) | (36,045,301) | | |
| 30 | | TOTAL Transmission NOn-EHV (Sum L's 24 Thru 29) | $ 2,304,488 | $ (36,251) | $ 1,936,284 | $ - | $ 184,414,017 | $ (6,353,626) | $ (312,156,225) | $ (127,742,208) | | |

**EXHIBIT B**
**TEST YEAR PLANT SCHEDULES - CONT'D**
**YEAR ENDED DECEMBER 31, 2005**

| LINE NO. | ACCT NO. | ACCOUNT NAME | (A) PLANT ADDITIONS | (B) PLANT RETIREM'TS | (C) PLANT ADJUSTM'TS | (D) PLANT TRANSFERS | (E) TOTAL PLANT VALUE | (F) ACCURAL DEPREC'N | (G) ACCUM'D DEPREC'N | (H) NET PLANT VALUE | (I) ACC. DEP. COMPANY WORKPAPERS | (J) ACC. DEP. DIFFERENCE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Transmission EHV (345 KV & Above) | | | | | | | | | | |
| 31 | 350 | Land and Land Rights | $ - | $ (102,500) | $ - | $ - | $ 15,045,905 | $ (339,686) | $ (578,025) | $ 14,467,880 | | |
| 32 | 352 | Structures and Improvements | 10,719 | - | - | - | 10,080,976 | (245,845) | (480,676) | 9,600,300 | | |
| 33 | 353 | Station Equipment | 414,395 | - | 3,971 | - | 115,575,862 | (4,060,907) | (7,995,625) | 107,580,237 | | |
| 34 | 354 | Towers and Fixtures | 53 | - | - | - | 145,722,526 | (5,144,004) | (10,288,052) | 135,434,474 | | |
| 35 | 355 | Poles and Fixtures | - | - | - | - | 1,341,221 | (60,891) | (121,783) | 1,219,438 | | |
| 36 | 356 | Overhead Conductors and Devices | 40,035 | - | - | - | 66,365,039 | (2,209,289) | (4,417,941) | 61,947,098 | | |
| 37 | 359 | Roads & Trails | - | - | (160,601) | - | 4,485,615 | (91,318) | (2,855,664) | 1,629,951 | | |
| 38 | | TOTAL Transmission EHV (Sum L's 31 Thru 36) | $ 465,202 | $ (102,500) | $ (156,630) | $ - | $ 358,617,144 | $ (12,151,941) | $ (26,737,766) | $ 331,879,378 | | |
| 39 | | TOTAL Transmission Plant (Sum L's 30 & 37) | $ 2,769,690 | $ (138,751) | $ 1,779,654 | $ - | $ 543,031,161 | $ (18,505,568) | $ (338,893,991) | $ 204,137,170 | $ (341,776,692) | $ 2,882,701 |
| | | DISTRIBUTION PLANT | | | | | | | | | | |
| 40 | 360 | Land and Land Rights | $ 753,876 | $ - | $ - | $ - | $ 9,514,952 | $ (130,173) | $ (2,613,993) | $ 6,900,959 | | |
| 41 | 361 | Structures and Improvements | 1,608,223 | - | - | - | 6,566,236 | (3,711,503) | (5,118,275) | 1,447,961 | | |
| 42 | 362 | Station Equipment | 4,405,746 | - | - | - | 90,931,121 | (5,615,221) | (60,657,899) | 30,273,222 | | |
| 43 | 364 | Poles, Towers, and Fixtures | 5,749,474 | (56,931) | - | - | 105,957,203 | (3,697,177) | (72,439,456) | 33,517,747 | | |
| 44 | 365 | Overhead Conductors and Devices | 4,881,171 | (29,242) | - | - | 103,021,410 | (1,209,623) | (53,116,534) | 49,904,876 | | |
| 45 | 366 | Underground Conduit | - | (10,769) | (306,015) | - | 49,172,387 | (3,002,092) | (16,174,947) | 32,997,440 | | |
| 46 | 367 | Underground Conductors and Devices | 15,311,324 | (139,733) | - | - | 199,507,392 | (6,178,805) | (48,764,179) | 150,743,213 | | |
| 47 | 368 | Line Transformers | 14,510,231 | (630,084) | - | - | 189,099,247 | (3,307,241) | (69,801,556) | 119,297,691 | | |
| 48 | 369 | Services | 9,047,110 | (62,233) | - | - | 88,395,733 | (1,222,509) | (40,499,850) | 47,895,883 | | |
| 49 | 370 | Meters | 3,068,208 | - | 894,668 | - | 31,726,620 | - | (9,650,386) | 22,076,234 | | |
| 50 | 371 | Installations on Customer Premises | - | - | - | - | - | (386,749) | (386,749) | (386,749) | | |
| 51 | 373 | Street Lighting and Signal Systems | 494,544 | (7,923) | - | - | 9,158,128 | - | (5,079,527) | 4,078,601 | | |
| 52 | 374 | Asset Retirement Obligation | 216,459 | - | - | - | 216,459 | - | - | 216,459 | | |
| 53 | | TOTAL Distribution Plant (Sum L's 39 Thru 51) | $ 60,046,366 | $ (936,915) | $ 588,653 | $ - | $ 883,266,888 | $ (28,461,092) | $ (384,303,351) | $ 498,963,537 | $ (386,659,796) | $ 2,356,445 |
| | | GENERAL PLANT | | | | | | | | | | |
| 54 | 389 | Land and Land Rights | $ - | $ - | $ - | $ - | $ 302,740 | $ - | $ - | $ 302,740 | | |
| 55 | 390 | Structures and Improvements | 2,483,742 | - | 155,548 | - | 34,316,325 | (1,115,288) | (9,906,369) | 24,409,956 | | |
| 56 | 391 | Office Furniture and Equipment | 5,756,092 | (6,681,627) | - | - | 24,727,514 | (3,370,460) | (11,732,219) | 12,995,295 | | |
| 57 | 392 | Transportation Equipment | 3,658,113 | - | 204,085 | - | 34,384,736 | (1,531,812) | (15,354,994) | 19,029,742 | | |
| 58 | 393 | Stores Equipment | - | (157,015) | - | - | 742,310 | (54,749) | (674,809) | 67,501 | | |
| 59 | 394 | Tools, Shop and Garage Equipment | - | (2,233,039) | (135,856) | - | 6,168,506 | (432,354) | (7,210,809) | (1,042,303) | | |
| 60 | 395 | Laboratory Equipment | 154,173 | (1,241,927) | - | - | 3,814,792 | (256,290) | (1,461,297) | 2,353,495 | | |
| 61 | 396 | Power Operated Equipment | 1,248,183 | (37,354) | - | - | 9,849,181 | (307,817) | (1,481,835) | 8,367,346 | | |
| 62 | 397 | Communication Equipment | 1,399,972 | (11,320,839) | - | - | 23,573,572 | (1,903,218) | (14,677,995) | 8,895,577 | | |
| 63 | 398 | Miscellaneous Equipment | 144,174 | (108,353) | - | - | 2,074,778 | (102,843) | (970,205) | 1,104,573 | | |
| 64 | | TOTAL General Plant (Sum L's 53 Thru 62) | $ 14,844,449 | $ (21,780,154) | $ 223,777 | $ - | $ 139,954,454 | $ (9,074,830) | $ (63,470,531) | $ 76,483,923 | $ (62,514,299) | $ (956,232) |
| 65 | | TOTAL PLANT(Sum L's 4, 23, 38, 52 & 63) | $ 122,163,380 | $ (37,857,499) | $ 3,342,084 | $ - | $ 2,857,083,735 | $ (93,259,816) | $ (1,375,522,805) | $ 1,481,560,930 | $ (1,349,758,765) | $ (25,764,040) |
| | | | | | | | | Company Workpapers | $ (1,349,758,766) | | | |
| | | | | | | | | Difference | $ (25,764,039) | | | |

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006



**EXHIBIT B**
**TEST YEAR PLANT SCHEDULES - CONT'D**
**TEST-YEAR ENDED DECEMBER 31, 2006**

| LINE NO. | ACCT NO. | ACCOUNT NAME | (A) PLANT ADDITIONS | (B) PLANT RETIREM'TS | (C) PLANT ADJUSTM'TS | (D) PLANT TRANSFERS | (E) TOTAL PLANT VALUE | (F) ACCURAL DEPREC'N | (G) ACCUM'D DEPREC'N | (H) NET PLANT VALUE | (I) ACC. DEP. COMPANY WORKPAPERS | (J) ACC. DEP. DIFFERENCE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **INTANGIBLE PLANT** | | | | | | | | | | |
| 1 | 301 | Organization | $ - | $ - | $ - | $ - | $ 29,362 | $ - | $ - | $ 29,362 | | |
| 2 | 302 | Franchises and Consents | - | - | - | - | 147,884 | - | - | 147,884 | | |
| 3 | 303 | Miscellaneous Intangible Plant | 20,180,040 | - | (22,582) | - | 78,397,798 | - | - | 78,397,798 | | |
| 4 | | TOTAL Intangible Plant (Sum L's 1, 2, 3) | $ 20,180,040 | $ - | $ (22,582) | $ - | $ 78,575,044 | $ - | $ - | $ 78,575,044 | $ - | $ - |
| | | **PRODUCTION PLANT** | | | | | | | | | | |
| | | Steam Production Plant | | | | | | | | | | |
| 5 | 310 | Land and Land Rights | $ - | $ - | $ - | $ - | $ 5,878,540 | $ (116,983) | $ (1,983,979) | $ 3,894,561 | | |
| 6 | 311 | Structures and Improvements | 160,631 | - | (3,385) | - | 121,134,420 | (3,631,674) | (52,071,940) | 69,062,480 | | |
| 7 | 312 | Boiler Plant Equipment | 20,892,004 | - | (5,602,632) | - | 707,073,200 | (23,011,198) | (370,984,524) | 336,088,676 | | |
| 8 | 313 | Engines and Engine-Driven Generators | - | - | - | - | - | - | - | - | | |
| 9 | 314 | Turbogenerator Units | 3,963,103 | - | (486,613) | - | 231,204,768 | (6,608,636) | (120,818,315) | 110,386,453 | | |
| 10 | 315 | Accessory Electric Equipment | 769,892 | - | (76,095) | - | 82,685,481 | (2,206,674) | (42,050,216) | 40,635,265 | | |
| 11 | 316 | Misc. Power Plant Equipment | 429,681 | - | (30,538) | - | 19,877,557 | (796,958) | (11,299,326) | 8,578,231 | | |
| 12 | 317 | Asset Retm't Costs for Steam Production | - | - | - | - | 366,915 | (8,916) | (70,047) | 296,868 | | |
| 13 | 114 | San Juan Acquisition Adjustment | - | - | - | - | 3,124,669 | (116,655) | (3,066,258) | 58,411 | | |
| 14 | | TOTAL Steam Plant (Sum L's 5 Thru 13) | $ 26,215,311 | $ - | $ (6,199,263) | $ - | $ 1,171,345,550 | $ (36,497,694) | $ (602,344,605) | $ 569,000,945 | $ (544,672,310) | $ (57,672,295) |
| | | Other Production Plant | | | | | | | | | | |
| 15 | 340 | Land and Land Rights | $ 1,526,387 | $ - | $ - | $ - | $ 1,928,015 | $ - | $ - | $ 1,928,015 | | |
| 16 | 341 | Structures and Improvements | 12,840,376 | - | - | - | 14,200,470 | (157,162) | (745,904) | 13,454,566 | | |
| 17 | 342 | Fuel Holders, Products, and Accessories | 11,430,397 | - | - | - | 12,595,292 | (161,682) | (330,374) | 12,264,918 | | |
| 18 | 343 | Prime Movers | - | - | - | - | 354,047 | (5,240) | (297,445) | 56,602 | | |
| 19 | 344 | Generators | 15,646,491 | - | - | - | 87,936,444 | (1,450,049) | (20,881,109) | 67,055,335 | | |
| 20 | 345 | Accessory Electric Equipment | - | - | - | - | 4,475,217 | (82,792) | (2,119,397) | 2,355,820 | | |
| 21 | 346 | Misc. Power Plant Equipment | 7,347,169 | - | - | - | 8,385,479 | (128,164) | (618,881) | 7,766,598 | | |
| 22 | | TOTAL Other Plant (Sum L's 15 Thru 21) | $ 48,790,820 | $ - | $ - | $ - | $ 129,874,964 | $ (1,985,088) | $ (24,993,110) | $ 104,881,854 | $ (23,682,119) | $ (1,310,991) |
| 23 | | TOTAL Production Plant (Sum L's 14 & 22) | $ 75,006,131 | $ - | $ (6,199,263) | $ - | $ 1,301,220,514 | $ (38,482,782) | $ (627,337,715) | $ 673,882,799 | $ (568,354,429) | $ (58,983,286) |
| | | **TRANSMISSION PLANT** | | | | | | | | | | |
| | | Transmission Non-EHV (138 KV & Below) | | | | | | | | | | |
| 24 | 350 | Land and Land Rights | $ 1,498 | $ - | $ 1,501 | $ (116,498) | $ 10,776,362 | $ (243,745) | $ (12,049,463) | $ (1,273,101) | | |
| 25 | 352 | Structures and Improvements | - | - | (3,812) | - | 7,634,167 | (186,320) | (8,765,559) | (1,131,392) | | |
| 26 | 353 | Station Equipment | 3,963,949 | - | - | - | 124,358,421 | (4,307,651) | (123,709,088) | 649,333 | | |
| 27 | 354 | Towers and Fixtures | 32,320 | - | - | - | 9,843,590 | (346,908) | (105,832,579) | (95,988,989) | | |
| 28 | 355 | Poles and Fixtures | 15,047 | - | - | - | 18,675,438 | (847,523) | (14,666,339) | 4,009,099 | | |
| 29 | 356 | Overhead Conductors and Devices | - | - | (316,584) | - | 16,703,460 | (561,496) | (53,626,842) | (36,923,362) | | |
| 30 | | TOTAL Transmission N0n-EHV (Sum L's 24 Thru 29) | $ 4,012,814 | $ - | $ (318,895) | $ (116,498) | $ 187,991,438 | $ (6,493,644) | $ (318,649,869) | $ (130,658,431) | | |

Tucson Electric Power Company
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**EXHIBIT B**
**TEST YEAR PLANT SCHEDULES - CONT'D**
**TEST-YEAR ENDED DECEMBER 31, 2006**

| LINE NO. | ACCT NO. | ACCOUNT NAME | (A) PLANT ADDITIONS | (B) PLANT RETIREM'TS | (C) PLANT ADJUSTM'TS | (D) PLANT TRANSFERS | (E) TOTAL PLANT VALUE | (F) ACCURAL DEPREC'N | (G) ACCUM'D DEPREC'N | (H) NET PLANT VALUE | (I) ACC. DEP. COMPANY WORKPAPERS | (J) ACC. DEP. DIFFERENCE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Transmission EHV (345 KV & Above) | | | | | | | | | | |
| 31 | 350 | Land and Land Rights | $ - | $ - | $ - | $ - | $ 15,045,905 | $ (338,533) | $ (916,558) | $ 14,129,347 | | |
| 32 | 352 | Structures and Improvements | - | - | (763) | - | 10,080,213 | (245,967) | (726,642) | 9,353,571 | | |
| 33 | 353 | Station Equipment | 18,757,841 | - | - | - | 134,333,703 | (4,398,408) | (12,394,034) | 121,939,669 | | |
| 34 | 354 | Towers and Fixtures | 88,179 | - | - | - | 145,810,705 | (5,145,562) | (15,433,614) | 130,377,091 | | |
| 35 | 355 | Poles and Fixtures | - | - | - | - | 1,341,221 | (60,891) | (182,674) | 1,158,547 | | |
| 36 | 356 | Overhead Conductors and Devices | 104,279 | - | - | - | 66,469,318 | (2,211,692) | (6,629,633) | 59,839,685 | | |
| 37 | 359 | Roads & Trails | 172,538 | - | - | - | 4,658,153 | (91,438) | (2,947,101) | 1,711,052 | | |
| 38 | | TOTAL Transmission EHV (Sum L's 31 Thru 36) | $ 19,122,837 | $ - | $ (763) | $ - | $ 377,739,218 | $ (12,492,490) | $ (39,230,257) | $ 338,508,961 | | |
| 39 | | TOTAL Transmission Plant (Sum L's 30 & 37) | $ 23,135,651 | $ - | $ (319,658) | $ (116,498) | $ 565,730,656 | $ (18,986,134) | $ (357,880,125) | $ 207,850,531 | $ (360,876,612) | $ 2,996,487 |
| | | DISTRIBUTION PLANT | | | | | | | | | | |
| 40 | 360 | Land and Land Rights | $ - | $ - | $ (88,834) | $ 432,627 | $ 9,858,745 | $ (215,048) | $ (2,829,041) | $ 7,029,704 | | |
| 41 | 361 | Structures and Improvements | - | - | (284,142) | - | 6,282,094 | (156,750) | (5,275,024) | 1,007,070 | | |
| 42 | 362 | Station Equipment | 4,520,539 | - | - | - | 95,451,660 | (3,960,634) | (64,618,533) | 30,833,127 | | |
| 43 | 364 | Poles, Towers, and Fixtures | 7,148,953 | - | (120,798) | - | 112,985,358 | (5,999,026) | (78,438,482) | 34,546,876 | | |
| 44 | 365 | Overhead Conductors and Devices | 3,900,846 | - | (163,714) | - | 106,758,542 | (3,838,973) | (56,955,507) | 49,803,035 | | |
| 45 | 366 | Underground Conduit | 182,260 | - | (12,163) | - | 49,342,484 | (1,147,698) | (17,322,646) | 32,019,838 | | |
| 46 | 367 | Underground Conductors and Devices | 14,098,127 | - | (230,975) | - | 213,374,544 | (3,364,988) | (52,129,167) | 161,245,377 | | |
| 47 | 368 | Line Transformers | 14,963,571 | - | (933,522) | - | 203,129,296 | (6,628,662) | (76,430,218) | 126,699,078 | | |
| 48 | 369 | Services | 4,494,204 | - | (870,175) | - | 92,019,762 | (3,454,957) | (43,954,807) | 48,064,955 | | |
| 49 | 370 | Meters | 2,632,000 | - | (1,476,831) | - | 32,881,789 | (1,224,329) | (10,874,716) | 22,007,073 | | |
| 50 | 371 | Installations on Customer Premises | - | - | - | - | - | - | (386,749) | (386,749) | | |
| 51 | 373 | Street Lighting and Signal Systems | 228,662 | - | (52,374) | - | 9,334,416 | (412,384) | (5,491,910) | 3,842,506 | | |
| 52 | 374 | Asset Retirement Obligation | - | - | - | - | 216,459 | - | - | 216,459 | | |
| 53 | | TOTAL Distribution Plant (Sum L's 39 Thru 51) | $ 52,169,162 | $ - | $ (4,233,528) | $ 432,627 | $ 931,635,149 | $ (30,403,449) | $ (414,706,800) | $ 516,928,349 | $ (410,531,529) | $ (4,175,271) |
| | | GENERAL PLANT | | | | | | | | | | |
| 54 | 389 | Land and Land Rights | $ - | $ - | $ - | $ - | $ 302,740 | $ - | $ - | $ 302,740 | | |
| 55 | 390 | Structures and Improvements | 1,430,472 | - | (322,328) | - | 35,424,469 | (1,178,619) | (11,084,988) | 24,339,481 | | |
| 56 | 391 | Office Furniture and Equipment | 3,938,026 | - | (2,534,876) | - | 26,130,664 | (3,402,412) | (15,134,631) | 10,996,033 | | |
| 57 | 392 | Transportation Equipment | 5,229,943 | - | (2,653,793) | - | 36,960,886 | (1,683,757) | (17,038,750) | 19,922,136 | | |
| 58 | 393 | Stores Equipment | 291,468 | - | (45,357) | - | 988,421 | (57,720) | (732,529) | 255,892 | | |
| 59 | 394 | Tools, Shop and Garage Equipment | 179,591 | - | (203,478) | - | 6,144,619 | (362,006) | (7,572,814) | (1,428,195) | | |
| 60 | 395 | Laboratory Equipment | 656,226 | - | (197,584) | - | 4,273,434 | (237,794) | (1,699,091) | 2,574,343 | | |
| 61 | 396 | Power Operated Equipment | - | - | (174,507) | - | 9,674,674 | (325,072) | (1,806,907) | 7,867,767 | | |
| 62 | 397 | Communication Equipment | 6,310,553 | - | (48,226) | - | 29,835,899 | (1,781,206) | (16,459,201) | 13,376,698 | | |
| 63 | 398 | Miscellaneous Equipment | 2,527,532 | - | (20,120) | - | 4,582,190 | (166,424) | (1,136,629) | 3,445,561 | | |
| 64 | | TOTAL General Plant (Sum L's 53 Thru 62) | $ 20,563,811 | $ - | $ (6,200,269) | $ - | $ 154,317,996 | $ (9,195,010) | $ (72,665,541) | $ 81,652,455 | $ (67,626,970) | $ (5,038,571) |
| 65 | | TOTAL PLANT(Sum L's 4, 23, 38, 52 & 63) | $ 191,054,795 | $ - | $ (16,975,300) | $ 316,129 | $ 3,031,479,359 | $ (97,067,376) | $ (1,472,590,181) | $ 1,558,889,178 | $ (1,407,389,540) | $ (65,200,641) |
| 66 | | | | | | | | Company Workpapers | $ (1,407,389,540) | | $ (65,200,641) | |
| 67 | | | | | | | | Difference | $ (65,200,641) | | $ (8,938,932) | 2004 |
| | | | | | | | | | | | $ (16,825,107) | 2005 |
| 69 | | | | | | | | | | | $ (39,436,602) | 2006 |
| 70 | | | | | | | | | | | $ (65,200,641) | |

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**REVENUE REQUIREMENT**
**ACC JURISDICTIONAL**
(Thousands of Dollars)

| LINE NO. | DESCRIPTION | (A) COMPANY ORIGINAL COST | (B) COMPANY RCND | (C) COMPANY FAIR VALUE | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|---|---|---|
| 1 | Adjusted Rate Base | $ 982,734 | $ 1,849,295 | $ 1,416,014 | $ 936,123 | $ 1,783,296 | $ 1,359,709 |
| 2 | Adjusted Operating Income (Loss) | $ (13,173) | $ (13,173) | $ (13,173) | $ 50,824 | $ 50,824 | $ 50,824 |
| 3 | Current Rate Of Return (Line 2 / Line 1) | -1.34% | -0.71% | -0.93% | 5.43% | 2.85% | 3.74% |
| 4 | Required Operating Income (Line 5 X Line 1) | $ 82,069 | $ 82,069 | $ 82,069 | $ 72,667 | $ 72,667 | $ 72,667 |
| 5 | Required Rate Of Return | 8.35% | 4.44% | 5.80% | 7.76% | 4.07% | 5.34% |
| 6 | Operating Income Deficiency (Line 4 - Line 2) | $ 95,242 | $ 95,242 | $ 95,242 | $ 21,843 | $ 21,843 | $ 21,843 |
| 7 | Gross Revenue Conversion Factor (Schedule RLM-1, Page 3) | 1.6609 | 1.6609 | 1.6609 | 1.6598 | 1.6598 | 1.6598 |
| 8 | Increase In Gross Revenue Requirement (Line 7 X Line 6) | $ 158,186 | $ 158,186 | $ 158,186 | $ 36,254 | $ 36,254 | $ 36,254 |
| 9 | Adjusted Test Year Revenue | $ 712,731 | $ 712,731 | $ 712,731 | $ 897,212 | $ 897,212 | $ 897,212 |
| 10 | Proposed Annual Revenue Requirement (Line 8 + Line 9) | $ 870,917 | $ 870,917 | $ 870,917 | $ 933,466 | $ 933,466 | $ 933,466 |
| 11 | Required Percentage Increase In Revenue (Line 8 / Line 9) | 22.19% | 22.19% | 22.19% | 4.04% | 4.04% | 4.04% |
| 12 | Rate Of Return On Common Equity | 11.39% | 11.39% | 11.39% | 9.44% | 9.44% | 9.44% |

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Column (D): Schedules RLM-1, Page 2, RLM-2, RLM-7 And RLM-18
Column (E): Schedule RLM-2, Column (F)
Column (F): Average Of Column (D) + Column (E)

Tucson Electric Power Company
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## GROSS REVENUE CONVERSION FACTOR

| LINE NO. | DESCRIPTION | REFERENCE | (A) |
|---|---|---|---|
| | CALCULATION OF GROSS REVENUE CONVERSION FACTOR: | | |
| 1 | Revenue | | 100.0% |
| 2 | Less: Uncollectibles | Company Response To Staff Data Request 1.85 | 0.25% |
| 3 | Subtotal | Line 1 - Line 2 | 99.7% |
| 4 | Less: Combined Federal And State Tax Rate | Line 14 | 39.5% |
| 5 | Subtotal | Line 3 - Line 4 | 60.25% |
| 6 | **Revenue Conversion Factoı** | Line 1 / Line 5 | **1.6598** |
| | CALCULATION OF EFFECTIVE TAX RATE: | | |
| 7 | Arizona Taxable Income | | 100.0% |
| 8 | Arizona State Income Tax Rate | | 7.1% |
| 9 | Federal Taxable Income | Line 7 - Line 8 | 92.9% |
| 10 | Applicable Federal Income Tax Rate | | 35.0% |
| 11 | Effective Federal Income Tax Rate | Line 9 X Line 10 | 32.5% |
| 12 | Subtotal | Line 8 + Line 11 | 39.6% |
| 13 | Revenue Less Uncollectibles | Line 3 | 99.7% |
| 14 | Combined Federal And State Income Tax Rat€ | Line 12 X Line 13 | 39.5% |

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**FAIR VALUE RATE BASE - OCRB / RCND (50/50 SPLIT)**
**ACC JURISDICTIONAL**
(Thousands of Dollars)

| LINE NO. | DESCRIPTION | (A) COMPANY OCRB | (B) COMPANY RCND | (C) COMPANY FVRB | (D) OCRB/RCND % DIFF. | (E) RUCO OCRB | (F) RUCO RCND | (G) RUCO FVRB |
|---|---|---|---|---|---|---|---|---|
| 1 | Gross Utility Plant In Service | $ 2,115,571 | $ 4,184,249 | $ 3,149,910 | 197.78% | $ 2,219,459 | $ 4,389,723 | $ 3,304,591 |
| 2 | Accumulated Depreciation | (1,026,758) | (2,062,696) | (1,544,727) | 200.89% | (1,159,791) | (2,329,951) | (1,744,871) |
| 3 | Net Utility Plant In Service | $ 1,088,813 | $ 2,121,553 | $ 1,605,183 | | $ 1,059,668 | $ 2,059,772 | $ 1,559,720 |
| 4 | Plant Held For Future Use | $ - | $ - | $ - | 100.00% | $ - | $ - | $ - |
| 5 | Total Net Utility Plant | $ 1,088,813 | $ 2,121,553 | $ 1,605,183 | | $ 1,059,668 | $ 2,059,772 | $ 1,559,720 |
| | Deductions: | | | | | | | |
| 6 | Cust. Advances For Const. | $ (5,978) | $ (6,635) | $ (6,307) | 110.99% | $ (5,978) | $ (6,635) | $ (6,307) |
| 7 | Customer Deposits | (12,538) | (12,538) | (12,538) | 100.00% | (12,538) | (12,538) | (12,538) |
| 8 | Def'd Credit - Cont'd Plt & Retm't Oblig. | (5,028) | (5,028) | (5,028) | 100.00% | (5,028) | (5,028) | (5,028) |
| 9 | Acc. Deferred Income Taxes | (160,264) | (325,785) | (243,025) | 203.28% | (147,437) | (299,711) | (223,574) |
| 10 | Total Deductions | $ (183,808) | $ (349,986) | $ (266,897) | | $ (170,981) | $ (323,912) | $ (247,447) |
| 11 | Allowance - Working Capital | $ 30,273 | $ 30,273 | $ 30,273 | 100.00% | $ 33,224 | $ 33,224 | $ 33,224 |
| 12 | Regulatory Assets | $ 47,455 | $ 47,455 | $ 47,455 | 100.00% | $ 14,213 | $ 14,213 | $ 14,213 |
| 13 | Regulatory Liability | $ - | $ - | $ - | 100.00% | $ - | $ - | $ - |
| 14 | **TOTAL TEST YEAR RATE BASE** | $ 982,733 | $ 1,849,295 | $ 1,416,014 | | $ 936,123 | $ 1,783,296 | $ 1,359,709 |

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule RLM-3, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F)

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Cost of Service
Schedule RLM-3


## ORIGINAL COST RATE BASE STATEMENT
(Thousands of Dollars)

| LINE NO. | DESCRIPTION | (A) COMPANY FILED AS OCRB | (B) RUCO ADJUSTMENTS | (C) RUCO ADJUSTED AS OCRB | (D) RUCO ADJUSTED OCRB ACC JURISDICTIONAL |
|---|---|---|---|---|---|
| 1 | Gross Utility Plant In Service | $ 2,880,566 | $ 141,454 | $ 3,022,020 | $ 2,219,459 |
| 2 | Accumulated Depreciation | (1,493,988) | (193,570) | (1,687,558) | (1,159,791) |
| 3 | Net Utility Plant In Service | $ 1,386,578 | $ (52,116) | $ 1,334,462 | $ 1,059,668 |
| 4 | Plant Held For Future Use | $ 4,014 | $ - | $ 4,014 | $ - |
| 5 | Total Net Utility Plant | $ 1,390,592 0 | $ (52,116) | $ 1,338,476 | $ 1,059,668 |
| | Deductions: | | | | |
| 6 | Cust. Advances For Const. | $ (5,978) | $ - | $ (5,978) | $ (5,978) |
| 7 | Customer Deposits | (12,538) | - | (12,538) | (12,538) |
| 8 | Def'd Credit - Cont'd Plt & Retm't Oblig. | (6,823) | - | (6,823) | (5,028) |
| 9 | Acc. Deferred Income Taxes | (217,503) | 17,408 | (200,095) | (147,437) |
| 10 | Total Deductions | $ (242,842) | $ 17,408 | $ (225,434) | $ (170,981) |
| 11 | Allowance - Working Capital | $ 40,488 | $ 3,946 | $ 44,434 | $ 33,224 |
| 12 | Regulatory Assets | $ 47,455 | $ (33,242) | $ 14,213 | $ 14,213 |
| 13 | Regulatory Liability | $ - | $ - | $ - | $ - |
| 14 | TOTAL OCRB | $ 1,235,693 | $ (64,004) | $ 1,171,689 | $ 936,123 |

References:
Column (A): - Company Schedule B-2
Column (B): - RUCO Adjustments (See RLM-4, Columns (B) Thru (G))
Column (C): - Sum Of Columns (A) And (B)
Column (D): - Column (C) Multipied By The Same Ratios As TEP's Percentage ACC Jurisdiction Is To Total Company

Tucson Electric Power Company
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**SUMMARY OF ORIGINAL COST RATE BASE**
(Thousands of Dollars)

| LINE NO. | DESCRIPTION | (A) COMPANY FILED AS OCRB | (B) ADJ. NO. 1 ACCUMULATED DEPRECIATION TESTIMONY-RLM | (C) ADJ. NO. 2 SPRINGERVILLE UNIT 1 TESTIMONY-MDC | (D) ADJ. NO. 3 LUNA PLANT TESTIMONY-MDC | (E) ADJ. NO. 4 REGULATORY ASSETS TESTIMONY-MDC | (F) ADJ. NO. 5 FAS 143 WRITE-OFF TESTIMONY-MDC | (G) ADJ. NO. 6 ALLOWANCE FOR WORKING CAPITAL SCH. RLM-6 | (H) RUCO ADJUSTED AS OCRB |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Utility Plant In Service | $ 2,880,566 | $ - | $ 92,524 | $ 48,930 | $ - | $ - | $ - | $ 3,022,020 |
| 2 | Accumulated Depreciation | (1,493,988) | (49,504) | (30,368) | (891) | - | (112,807) | - | (1,687,558) |
| 3 | Net Utility Plant In Service | $ 1,386,578 | $ (49,504) | $ 62,156 | $ 48,039 | $ - | $ (112,807) | $ - | $ 1,334,462 |
| 4 | Plant Held For Future Use | $ 4,014 | $ - | $ - | $ - | $ - | $ - | $ - | $ 4,014 |
| 5 | Total Net Utility Plant | $ 1,390,592 0 | $ (49,504) | $ 62,156 | $ 48,039 | $ - | $ (112,807) | $ - | $ 1,338,477 |
| | Deductions: | | | | | | | | |
| 6 | Cust. Advances For Const. | $ (5,978) | $ - | $ - | $ - | $ - | $ - | $ - | $ (5,978) |
| 7 | Customer Deposits | (12,538) | - | - | - | - | - | - | (12,538) |
| 8 | Def'd Credit - Plt & Retm't | (6,823) | - | - | - | - | - | - | (6,823) |
| 9 | Acc. Deferred Income Taxes | (217,503) | 19,554 | (1,764) | (382) | - | - | - | (200,095) |
| 10 | Total Deductions | $ (242,842) | $ 19,554 | $ (1,764) | $ (382) | $ - | $ - | $ - | $ (225,434) |
| 11 | Allowance - Working Capital | $ 40,488 | $ - | $ - | $ - | $ - | $ - | $ 3,946 | $ 44,434 |
| 12 | Regulatory Assets | $ 47,455 | $ - | $ - | | $ (33,242) | $ - | $ - | $ 14,213 |
| 13 | Regulatory Liability | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | TOTAL OCRB | $ 1,235,693 | $ (29,949) | $ 60,392 | $ 47,657 | $ (33,242) | $ (112,807) | $ 3,946 | $ 1,171,689 |

References:
Column (A): Company Schedule B-1
Columns (B) Thru (G): RUCO Rate Base Adjustments
Column (H): Sum Of Columns (A) Through (G)

## TEST YEAR PLANT SCHEDULES
## PRO FORMA ADJUSTMENTS TO TEST-YEAR ENDED DECEMBER 31, 2006

| LINE NO. | ACCT NO. | DESCRIPTION | (A) COMPANY AS FILED GROSS PLANT | (B) COMPANY AS FILED ACCUM. DEP. | (C) RUCO ADJ. NO. 1 ACCUMULATED DEPRECIATION RLM WP'S | (D) RUCO ADJ. NO. 2 SPRINGERVILLE UNIT 1 GROSS PLANT TESTIMONY-MDC | (E) RUCO ADJ. NO. 2 SPRINGERVILLE UNIT 1 ACCUM. DEP. TESTIMONY-MDC | (F) RUCO ADJ. NO. 3 LUNA PLANT GROSS PLANT TESTIMONY-MDC | (G) RUCO ADJ. NO. 3 LUNA PLANT ACCUM. DEP. TESTIMONY-MDC | (H) RUCO ADJ. NO. 5 FAS 143 WRITE-OFF TESTIMONY-MDC | (I) TOTAL PLANT VALUE | (J) ACCUM'D DEPREC'N | (K) NET PLANT VALUE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **INTANGIBLE PLANT** | | | | | | | | | | | |
| 1 | 301 | Organization | $ 29,362 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 29,362 | $ - | $ 29,362 |
| 2 | 302 | Franchises and Consents | 147,884 | (147,884) | - | - | - | - | - | (11,237) | 147,884 | (159,121) | (11,237) |
| 3 | 303 | Miscellaneous Intangible Plant | 68,762,926 | (37,114,783) | - | 234,384 | (259,958) | - | - | (2,820,181) | 68,997,310 | (40,194,922) | 28,802,388 |
| 4 | | TOTAL Intangible Plant | $ 68,940,172 | $ (37,262,667) | $ - | $ 234,384 | $ (259,958) | $ - | $ - | $ (2,831,418) | $ 69,174,556 | $ (40,354,043) | $ 28,820,513 |
| | | **PRODUCTION PLANT** | | | | | | | | | | | |
| | | Steam Production Plant | | | | | | | | | | | |
| 5 | 310 | Land and Land Rights | $ 3,169,168 | $ (1,012,696) | $ 390,382 | $ 2,709,372 | $ (1,288,605) | $ - | $ - | $ (76,950) | $ 5,878,540 | $ (1,987,870) | $ 3,890,670 |
| 6 | 311 | Structures and Improvements | 99,277,925 | (57,575,525) | (3,181,865) | 21,856,495 | (12,760,129) | - | - | (4,374,898) | 121,134,420 | (77,892,417) | 43,242,003 |
| 7 | 312 | Boiler Plant Equipment | 662,377,491 | (354,059,358) | (33,997,147) | 44,695,709 | (8,520,420) | - | - | (26,903,334) | 707,073,200 | (423,480,259) | 283,592,941 |
| 8 | 313 | Engines and Engine-Driven Generators | - | - | - | - | - | - | - | - | - | - | - |
| 9 | 314 | Turbogenerator Units | 218,716,218 | (113,122,101) | (8,948,532) | 12,488,550 | (3,465,561) | - | - | (8,595,626) | 231,204,768 | (134,131,819) | 97,072,949 |
| 10 | 315 | Accessory Electric Equipment | 81,654,743 | (43,596,052) | (2,479,779) | 1,030,738 | (212,503) | - | - | (3,312,662) | 82,685,481 | (49,600,997) | 33,084,484 |
| 11 | 316 | Misc. Power Plant Equipment | 19,036,662 | (10,453,046) | (1,365,514) | 840,896 | (193,805) | - | - | (794,279) | 19,877,558 | (12,806,643) | 7,070,915 |
| 12 | 317 | Asset Retm't Costs for Steam Production | 344,128 | (185,057) | (9,963) | - | - | 22,787 | (242) | (14,062) | 366,915 | (209,323) | 157,592 |
| 13 | 114 | San Juan Acquisition Adjustment | 3,124,669 | (2,860,427) | - | - | - | - | - | (217,351) | 3,124,669 | (3,077,778) | 46,891 |
| 14 | | TOTAL Steam Plant | $ 1,087,701,004 | $ (582,864,262) | $ (49,592,418) | $ 83,621,760 | $ (26,441,023) | $ 22,787 | $ (242) | $ (44,289,161) | $ 1,171,345,551 | $ (703,187,106) | $ 468,158,445 |
| | | Other Production Plant | | | | | | | | | | | |
| 15 | 340 | Land and Land Rights | $ 401,628 | $ - | $ - | $ - | $ - | $ 1,526,387 | $ (27,787) | $ - | $ 1,928,015 | $ (27,787) | $ 1,900,228 |
| 16 | 341 | Structures and Improvements | 1,360,094 | (636,837) | 45,964 | - | - | 12,840,376 | (233,748) | (48,390) | 14,200,470 | (873,011) | 13,327,459 |
| 17 | 342 | Fuel Holders, Products, and Accessories | 1,164,895 | (197,799) | 3,655 | - | - | 11,430,397 | (208,081) | (15,030) | 12,595,292 | (417,255) | 12,178,037 |
| 18 | 343 | Prime Movers | 354,047 | (347,068) | - | - | - | - | - | (26,372) | 354,047 | (373,440) | (19,393) |
| 19 | 344 | Generators | 62,855,652 | (22,186,621) | 22,444 | - | - | 15,622,018 | (284,386) | (1,685,859) | 78,477,670 | (24,134,422) | 54,343,248 |
| 20 | 345 | Accessory Electric Equipment | 4,475,217 | (2,256,626) | 51,299 | - | - | - | - | (171,471) | 4,475,217 | (2,376,798) | 2,098,419 |
| 21 | 346 | Misc. Power Plant Equipment | 1,038,310 | (513,791) | (34,779) | - | - | 7,347,169 | (133,749) | (39,041) | 8,385,479 | (721,360) | 7,664,119 |
| 22 | | TOTAL Other Plant | $ 71,649,843 | $ (26,138,742) | $ 88,583 | $ - | $ - | $ 48,766,347 | $ (887,751) | $ (1,986,162) | $ 120,416,190 | $ (28,924,072) | $ 91,492,118 |
| 23 | | TOTAL Production Plant | $ 1,159,350,847 | $ (609,003,004) | $ (49,503,835) | $ 83,621,760 | $ (26,441,023) | $ 48,789,134 | $ (887,993) | $ (46,275,323) | $ 1,291,761,741 | $ (732,111,178) | $ 559,650,563 |
| | | **TRANSMISSION PLANT** | | | | | | | | | | | |
| | | Transmission Non-EHV (138 KV & Below) | | | | | | | | | | | |
| 24 | 350 | Land and Land Rights | $ 10,776,362 | $ (3,933,982) | $ - | $ 8,686 | $ - | $ - | $ - | $ (298,925) | $ 10,785,048 | $ (4,232,907) | $ 6,552,141 |
| 25 | 352 | Structures and Improvements | 7,634,167 | (3,082,538) | - | - | - | - | - | (234,228) | 7,634,167 | (3,316,766) | 4,317,401 |
| 26 | 353 | Station Equipment | 124,358,421 | (64,239,317) | - | - | - | 141,051 | (3,127) | (4,881,249) | 124,499,472 | (69,123,693) | 55,375,779 |
| 27 | 354 | Towers and Fixtures | 9,843,590 | (9,179,276) | - | - | - | - | - | (697,491) | 9,843,590 | (9,876,767) | (33,177) |
| 28 | 355 | Poles and Fixtures | 18,675,438 | (13,689,183) | - | - | - | - | - | (1,040,178) | 18,675,438 | (14,729,361) | 3,946,077 |
| 29 | 356 | Overhead Conductors and Devices | 16,703,460 | (9,777,611) | - | - | - | - | - | (742,955) | 16,703,460 | (10,520,566) | 6,182,894 |
| 30 | | TOTAL Transmission Non-EHV | $ 187,991,438 | $ (103,901,907) | $ - | $ 8,686 | $ - | $ 141,051 | $ (3,127) | $ (7,895,026) | $ 188,141,175 | $ (111,800,060) | $ 76,341,115 |

Continued On Page 2

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

Cost of Service
Schedule RLM-5
Pages 1 & 2 of 2

# TEST YEAR PLANT SCHEDULES
## PRO FORMA ADJUSTMENTS TO TEST-YEAR ENDED DECEMBER 31, 2006

| LINE NO. | ACCT NO. | DESCRIPTION | (A) COMPANY AS FILED GROSS PLANT | (B) COMPANY AS FILED ACCUM. DEP. | (C) RUCO ADJ. NO. 1 ACCUMULATED DEPRECIATION RLM WP'S | (D) RUCO ADJ. NO. 2 SPRINGERVILLE UNIT 1 GROSS PLANT TESTIMONY-MDC | (E) RUCO ADJ. NO. 2 SPRINGERVILLE UNIT 1 ACCUM. DEP. TESTIMONY-MDC | (F) RUCO ADJ. NO. 3 LUNA PLANT GROSS PLANT TESTIMONY-MDC | (G) RUCO ADJ. NO. 3 LUNA PLANT ACCUM. DEP. TESTIMONY-MDC | (H) RUCO ADJ. NO. 5 FAS 143 WRITE-OFF TESTIMONY-MDC | (I) TOTAL PLANT VALUE | (J) ACCUM'D DEPREC'N | (K) NET PLANT VALUE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Transmission EHV (345 KV & Above) | | | | | | | | | | | |
| 31 | 350 | Land and Land Rights | $ 15,037,219 | $ (9,104,523) | $ - | $ - | $ - | $ - | $ - | $ (691,811) | $ 15,037,219 | $ (9,796,334) | $ 5,240,885 |
| 32 | 352 | Structures and Improvements | 10,080,213 | (6,412,850) | - | - | - | - | - | (487,283) | 10,080,213 | (6,900,133) | 3,180,080 |
| 33 | 353 | Station Equipment | 134,192,652 | (74,118,405) | - | - | - | - | - | (5,631,915) | 134,192,652 | (79,750,320) | 54,442,332 |
| 34 | 354 | Towers and Fixtures | 145,810,705 | (112,092,110) | - | - | - | - | - | (8,517,361) | 145,810,705 | (120,609,471) | 25,201,234 |
| 35 | 355 | Poles and Fixtures | 1,341,221 | (1,162,682) | - | - | - | - | - | (88,347) | 1,341,221 | (1,251,029) | 90,192 |
| 36 | 356 | Overhead Conductors and Devices | 66,469,318 | (51,136,689) | - | - | - | - | - | (3,885,641) | 66,469,318 | (55,022,330) | 11,446,988 |
| 37 | 359 | Roads & Trails | 4,658,153 | (2,944,319) | - | - | - | - | - | (223,725) | 4,658,153 | (3,168,044) | 1,490,109 |
| 38 | | TOTAL Transmission EHV | $ 377,589,481 | $ (256,971,578) | $ - | $ - | $ - | $ - | $ - | $ (19,526,082) | $ 377,589,481 | $ (276,497,660) | $ 101,091,821 |
| 39 | | TOTAL Transmission Plant | $ 565,580,919 | $ (360,873,485) | $ - | $ 8,686 | $ - | $ 141,051 | $ (3,127) | $ (27,421,108) | $ 565,730,656 | $ (388,297,720) | $ 177,432,936 |
| | | DISTRIBUTION PLANT | | | | | | | | | | | |
| 40 | 360 | Land and Land Rights | $ 9,858,745 | $ (3,742,566) | $ - | $ - | $ - | $ - | $ - | $ (284,380) | $ 9,858,745 | $ (4,026,946) | $ 5,831,799 |
| 41 | 361 | Structures and Improvements | 6,282,094 | (1,745,626) | - | - | - | - | - | (132,642) | 6,282,094 | (1,878,268) | 4,403,826 |
| 42 | 362 | Station Equipment | 95,451,660 | (62,914,013) | - | - | - | - | - | (4,780,545) | 95,451,660 | (67,694,558) | 27,757,102 |
| 43 | 364 | Poles, Towers, and Fixtures | 112,985,358 | (80,393,163) | - | - | - | - | - | (6,108,705) | 112,985,358 | (86,501,868) | 26,483,490 |
| 44 | 365 | Overhead Conductors and Devices | 106,758,542 | (59,293,992) | - | - | - | - | - | (4,505,476) | 106,758,542 | (63,799,468) | 42,959,074 |
| 45 | 366 | Underground Conduit | 49,342,484 | (15,411,170) | - | - | - | - | - | (1,171,024) | 49,342,484 | (16,582,194) | 32,760,290 |
| 46 | 367 | Underground Conductors and Devices | 213,374,544 | (48,689,625) | - | - | - | - | - | (3,699,700) | 213,374,544 | (52,389,325) | 160,985,219 |
| 47 | 368 | Line Transformers | 203,129,296 | (80,023,005) | - | - | - | - | - | (6,080,578) | 203,129,296 | (86,103,583) | 117,025,713 |
| 48 | 369 | Services | 92,019,762 | (42,610,100) | - | - | - | - | - | (3,237,745) | 92,019,762 | (45,847,845) | 46,171,917 |
| 49 | 370 | Meters | 32,881,789 | (11,171,975) | - | - | - | - | - | (848,907) | 32,881,789 | (12,020,882) | 20,860,907 |
| 50 | 371 | Installations on Customer Premises | - | - | - | - | - | - | - | - | - | - | - |
| 51 | 373 | Street Lighting and Signal Systems | 9,334,416 | (5,838,098) | - | - | - | - | - | (443,610) | 9,334,416 | (6,281,708) | 3,052,708 |
| 52 | 374 | Asset Retirement Obligation | 216,459 | (183,358) | - | - | - | - | - | (13,933) | 216,459 | (197,291) | 19,168 |
| 53 | | TOTAL Distribution Plant | $ 931,635,149 | $ (412,016,691) | $ - | $ - | $ - | $ - | $ - | $ (31,307,244) | $ 931,635,149 | $ (443,323,935) | $ 488,311,214 |
| | | GENERAL PLANT | | | | | | | | | | | |
| 54 | 389 | Land and Land Rights | $ 302,740 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 302,740 | $ - | $ 302,740 |
| 55 | 390 | Structures and Improvements | 35,331,795 | (11,701,598) | - | 92,674 | 16,877 | - | - | (889,150) | 35,424,469 | (12,573,871) | 22,850,598 |
| 56 | 391 | Office Furniture and Equipment | 25,057,825 | (11,647,647) | - | 1,072,839 | (839,178) | - | - | (885,051) | 26,130,664 | (13,371,876) | 12,758,788 |
| 57 | 392 | Transportation Equipment | 36,960,886 | (20,376,114) | - | - | - | - | - | (1,548,287) | 36,960,886 | (21,924,401) | 15,036,485 |
| 58 | 393 | Stores Equipment | 787,309 | (482,899) | - | 201,112 | (211,417) | - | - | (36,693) | 988,421 | (731,009) | 257,412 |
| 59 | 394 | Tools, Shop and Garage Equipment | 4,506,445 | (1,920,381) | - | 1,638,174 | (986,481) | - | - | (145,921) | 6,144,619 | (3,052,783) | 3,091,836 |
| 60 | 395 | Laboratory Equipment | 3,619,398 | (1,183,270) | - | 654,036 | (320,650) | - | - | (89,911) | 4,273,434 | (1,593,831) | 2,679,603 |
| 61 | 396 | Power Operated Equipment | 7,368,515 | (1,298,100) | - | 2,306,159 | (475,286) | - | - | (98,637) | 9,674,674 | (1,872,023) | 7,802,651 |
| 62 | 397 | Communication Equipment | 29,097,434 | (16,165,626) | - | 738,465 | (417,838) | - | - | (1,228,351) | 29,835,899 | (17,811,815) | 12,024,084 |
| 63 | 398 | Miscellaneous Equipment | 2,626,329 | (656,781) | - | 1,955,861 | (432,974) | - | - | (49,906) | 4,582,190 | (1,139,661) | 3,442,529 |
| 64 | | TOTAL General Plant | $ 145,658,676 | $ (65,432,416) | $ - | $ 8,659,320 | $ (3,666,947) | $ - | $ - | $ (4,971,907) | $ 154,317,996 | $ (74,071,270) | $ 80,246,726 |
| 65 | | SUB-TOTAL PLANT | $ 2,871,165,763 | $ (1,484,588,263) | $ (49,503,835) | $ 92,524,150 | $ (30,367,928) | $ 48,930,185 | $ (891,120) | $ (112,807,000) | $ 3,012,620,098 | $ (1,678,158,146) | $ 1,334,461,952 |
| 66 | | Reconcile Co.'s Workpapers To B-1 (Regulatory Assets) | $ 9,400,488 | (9,400,036) | | | | | | | 9,400,488 | (9,400,036) | 452 |
| 67 | | TOTAL PLANT | $ 2,880,566,251 | $ (1,493,988,299) | $ (49,503,835) | $ 92,524,150 | $ (30,367,928) | $ 48,930,185 | $ (891,120) | $ (112,807,000) | 3,022,020,586 | (1,687,558,181) | $ 1,334,462,405 |

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006



**ORIGINAL COST RATE BASE ADJUSTMENT NO. 6**
**ALLOWANCE FOR WORKING CAPITAL**
(Thousands of Dollars)

| LINE NO. | DESCRIPTION | REFERENCE | | (A) AMOUNT |
|---|---|---|---|---|
| 1 | Cash Working Capital Per TEP | TEP SCH. B-5, Page 1 | $ | (25,022) |
| 2 | Cash Working Capital Per RUCO | RLM-6, Page 2, Line 35 | | (21,796) |
| 3 | Adjustment | Line 2 - Line 1 | $ | 3,226 |
| 4 | Fuel Inventory Per TEP | TEP SCH. B-5, Page 1 | $ | 18,972 |
| 5 | Fuel Inventory Per RUCO | TEP SCH. B-5, Page 1 | | 18,972 |
| 6 | Adjustment | Line 5 - Line 4 | $ | - |
| 7 | Materials And Supplies Per TEP | TEP SCH. B-5, Page 1 | $ | 351,825 |
| 8 | Materials And Supplies Per RUCO | TEP SCH. B-5, Page 1 | | 351,825 |
| 9 | Materials And Supplies Per RUCO Luna Plant Rate Base Adjustment No. 2 | | | 629 |
| 10 | Adjustment | Line 8 - Line 7 + Line 9 | $ | 629 |
| 11 | Prepayments Per TEP | TEP SCH. B-5, Page 1 | $ | 5,895 |
| 12 | Prepayments Per RUCO | TEP SCH. B-5, Page 1 | | 5,895 |
| 13 | Prepayments Per RUCO Luna Plant Rate Base Adjustment No. 2 | | | 91 |
| 14 | Adjustment | Line 12 - Line 11 + Line 13 | $ | 91 |
| 15 | TOTAL ADJUSTMENT (See RLM-4, Column (G)) | Sum Lines 3, 6, 10 & 14 | $ | 3,946 |

**ORIGINAL COST RATE BASE ADJUSTMENT NO. 6 - CONT'D**
**ALLOWANCE FOR WORKING CAPITAL**
**LEAD/LAG DAY SUMMARY**

| LINE NO. | DESCRIPTION | (A) COMPANY EXPENSES AS FILED | (B) RUCO ADJUSTM'TS | (C) RUCO EXPENSES AS ADJUSTED | (D) (LEAD) / LAG DAYS | (E) DOLLAR DAYS |
|---|---|---|---|---|---|---|
| | OPERATING EXPENSES | | | | | |
| | Non-Cash Expenses: | | | | | |
| 1 | Bad Debts Expense | $ 2,490,991 | $ (2,490,991) | $ - | 0 | $ - |
| 2 | Depreciation | 82,440,295 | (82,440,295) | $ - | 0 | - |
| 3 | Amortization | 12,587,778 | (12,587,778) | $ - | 0 | - |
| 4 | Deferred Income Taxes | (8,038,493) | 8,038,493 | $ - | 0 | - |
| 5 | Total Non-Cash Expenses | $ 89,480,571 | $ (89,480,571) | $ - | | $ - |
| | Other Operating Expenses: | | | | | |
| 6 | Salaries & Wages | $ 60,946,931 | $ 19,651 | $ 60,966,582 | 13.26 | $ 808,416,871 |
| 7 | Incentive Pay | 3,838,440 | (1,525,378) | 2,313,062 | 244.32 | 565,127,308 |
| 8 | Fuel Expense | 257,956,424 | 23,216,300 | 281,172,724 | 24.1 | 6,776,262,643 |
| 9 | Purchased Power | 70,668,694 | 126,343,000 | 197,011,694 | 35.7 | 7,033,317,476 |
| 10 | Purchase Transmission | 4,771,517 | - | 4,771,517 | 39.5 | 188,474,922 |
| 11 | Lease Expense | 102,740,975 | (27,721,230) | 75,019,745 | 95.32 | 7,150,882,093 |
| 12 | Remote Generating Plant O & M | 31,798,784 | - | 31,798,784 | -0.7 | (22,259,149) |
| 13 | Office Supplies and Expenses | 6,542,004 | (420,344) | 6,121,660 | 5.1 | 31,220,465 |
| 14 | Outside Services | 6,361,869 | (309,734) | 6,052,135 | 35.9 | 217,271,653 |
| 15 | Property Insurance | 2,091,138 | (108,526) | 1,982,612 | 7.4 | 14,671,329 |
| 16 | Injuries and Damages | 3,635,397 | (15,381) | 3,620,016 | 19.7 | 71,314,315 |
| 17 | Pensions and Benefits | 15,825,396 | (1,683,208) | 14,142,188 | 11.4 | 161,220,939 |
| 18 | Miscellaneous General Expenses | 9,269,497 | (216,245) | 9,053,252 | 48.4 | 438,177,397 |
| 19 | Rents | 660,232 | (5,947) | 654,285 | 46.1 | 30,162,539 |
| 20 | Property Taxes | 30,751,385 | (1,800,201) | 28,951,184 | 213.78 | 6,189,184,176 |
| 21 | Payroll Taxes | 5,508,194 | (84,578) | 5,423,616 | 12.91 | 70,018,882 |
| 22 | Current Income Taxes | (4,221,970) | 50,695,903 | 46,473,933 | 42.3 | 1,965,847,348 |
| 23 | Other Taxes | 179,866 | - | 179,866 | 90.81 | 16,333,631 |
| 24 | Interest on Customer Deposits | 574,863 | - | 574,863 | 182.5 | 104,912,498 |
| 25 | Other Operations and Maintenance | 58,358,617 | (30,499,097) | 27,859,520 | 14.3 | 398,391,138 |
| 26 | Total Other Operating Expenses | $ 668,258,253 | $ 135,884,984 | $ 804,143,237 | | $ 32,208,948,473 |
| | Other Cash Working Capital Elements: | | | | | |
| 27 | Interest on Long-Term Debt | $ 43,417,161 | $ (2,238,155) | $ 41,179,006 | 74.6 | $ 3,071,953,877 |
| 28 | Revenue Taxes and Assessments | 59,055,220 | 9,874,581 | 68,929,801 | 51.75 | 3,567,117,215 |
| 29 | Total Other Cash Working Capital | $ 102,472,381 | $ 7,636,427 | $ 110,108,808 | | $ 6,639,071,093 |
| 30 | TOTAL CASH WORKING CAPITAL | $ 860,211,205 | | $ 914,252,045 | | $ 38,848,019,566 |

| | | | |
|---|---|---|---|
| 31 | Expense Lag | Line 31, Col. (E) / (D) | 42.49 |
| 32 | Revenue Lag | Company Workpapers | 33.79 |
| 33 | Net Lag | Line 28 - Line 27 | (8.70) |
| 34 | RUCO Adjusted Expenses | Col. (C), Line 31 | $ 914,252,045 |
| 35 | Cash Working Capital | Line 29 X Line 30 / 365 Days | (21,795,734) |

References:
Column (A): - Company Schedule B-5, Page 3
Column (B): RUCO Operating Income Adjustments (See RLM-7)
Column (C): Column (A) + (B)
Column (D): Company Schedule B-5, Page 3
Column (E): Column (C) X Column (D)

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

Cost of Service
Schedule RLM-7


**OPERATING INCOME STATEMENT**
(Thousands of Dollars)

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) RUCO TEST YEAR ADJM'TS | (C) RUCO TEST YEAR AS ADJ'D | (D) RUCO AS ADJ'D ACC JURID'L | (E) RUCO PROPOSED ACC JURID'L | (F) RUCO RECOM'D ACC JURID'L |
|---|---|---|---|---|---|---|---|
| | Operating Revenues: | | | | | | |
| 1 | Electric Retail Revenues | $ 691,451 | $ - | $ 691,451 | $ 691,451 | $ 36,254 | $ 727,705 |
| 2 | Sales for Resale | 58,402 | 183,785 | 242,187 | 183,785 | - | 183,785 |
| 3 | Other Operating Revenue | 34,542 | 1,130 | 35,671 | 21,976 | - | 21,976 |
| 4 | TOTAL OPERATING REVENUES | $ 784,395 | $ 184,915 | $ 969,310 | $ 897,212 | $ 36,254 | $ 933,466 |
| | Operating Expenses: | | | | | | |
| 5 | Fuel Expense | $ 265,955 | $ 23,216 | $ 289,172 | $ 258,992 | $ - | $ 258,992 |
| 6 | Purchased Power - Demand | 30,634 | (15,960) | 14,674 | 13,871 | - | 13,871 |
| 7 | Purchased Power - Energy | 40,035 | 126,343 | 166,378 | 149,015 | - | 149,015 |
| 8 | Other O & M Expense | 315,104 | (54,670) | 260,434 | 304,293 | - | 304,293 |
| 9 | Depreciation and Amortization | 82,440 | 3,812 | 86,253 | 60,592 | - | 60,592 |
| 10 | Taxes Other than Income Taxes | 35,831 | (1,885) | 33,946 | 27,562 | - | 27,562 |
| 11 | Income Taxes | (12,260) | - | - | 32,063 | 14,411 | 46,474 |
| 12 | TOTAL OPERATING EXPENSES | $ 757,739 | $ 80,857 | $ 850,856 | $ 846,388 | $ 14,411 | $ 860,799 |
| 13 | OPERATING INCOME (LOSS) | $ 26,656 | $ 104,058 | $ 118,454 | $ 50,824 | $ 21,843 | $ 72,667 |

References:
Column (A): Company Schedule C-1
Column (B): Testimonies, RLM & MDC And Schedule RLM-8, Pages 1 Thru 6
Column (C): Column (A) + Column (B)
Column (D): Column (C) X Jurisdictional Factor
Column (E): See Schedule RLM-1
Column (F): Column (D) + Column (E)

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

Cost of Service
Schedule RLM-8
Pages 1 & 2 of 6

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

| LINE NO. | FERC ACC'T | DESCRIPTION | (A) COMPANY AS FILED | (B) ADJ. NO. 1 SPRINGERVILLE UNIT 1 TESTIMONY-MDC | (C) ADJ. NO. 2 DEP/AMORT EXPENSES SCH. RLM-9 | (D) ADJ. NO. 3 INAPPROPRIATE EXPENSES SCH. RLM-10 | (E) ADJ. NO. 4 SERP TESTIMONY-RLM | (F) ADJ. NO. 5 INCENTIVE COMP. SCH. RLM-11 | (G) ADJ. NO. 6 RATE CASE EXPENSE TESTIMONY-RLM | (H) ADJ. NO. 7 PROPERTY TAX SCH. RLM-12 | (I) ADJ. NO. 8 O/H LINES MAINTENANCE SCH. RLM-13 | (J) ADJ. NO. 9 PENALTIES & FINES TESTIMONY-RLM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 440, 442, 444,445 | **Electric Retail Revenue** | $ 691,451,429 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2 | 446 | **Sales for Resale** | 58,402,097 | - | - | - | - | - | - | - | - | - |
| 3 | 447 | **Total Electric Retail Revenue** | $ 749,853,526 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | **Other Operating Revenue** | | | | | | | | | | |
| 4 | 451 | Miscellaneous Service Revenues | $ 3,810,771 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 5 | 454 | Rent from Electric Property | 9,846,702 | 566,941 | - | - | - | - | - | - | - | - |
| 6 | 456 | Other Electric Revenues | 20,884,206 | - | - | - | - | - | - | - | - | - |
| 7 | | **Total Other Operating Revenue** | $ 34,541,678 | $ 566,941 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | **Total Operating Revenue** | | $ 784,395,204 | $ 566,941 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | **Steam Power Generation Expense** | | | | | | | | | | |
| 9 | 500 | Operation Supervision & Engineering | $ 7,083,655 | $ (238,149) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 10 | 501 | Fuel - **PPFAC Eligible** | 239,090,290 | - | - | - | - | - | - | - | - | - |
| 11 | 502 | Steam Expenses | 22,290,946 | (2,453,630) | - | - | - | - | - | - | - | - |
| 12 | 505 | Electric Expenses | 3,358,046 | (169,923) | - | - | - | - | - | - | - | - |
| 13 | 506 | Miscellaneous Steam Power Expenses | 6,417,825 | (368,155) | - | - | - | (241,872) | - | - | - | - |
| 14 | 507 | Rents | 95,556,277 | (23,367,388) | - | - | - | - | - | - | - | - |
| 15 | 510 | Maintenance Supervision & Engineering | 4,910,476 | (287,729) | - | - | - | - | - | - | - | - |
| 16 | 511 | Maintenance of Structures | 2,391,982 | (190,264) | - | - | - | - | - | - | - | - |
| 17 | 512 | Maintenance of Boiler Plant | 29,145,633 | (2,591,774) | - | - | - | - | - | - | - | - |
| 18 | 513 | Maintenance of Electric Plant | 7,014,200 | (404,665) | - | - | - | - | - | - | - | - |
| 19 | 514 | Maintenance Miscellaneous Steam Plant | 7,562,772 | (595,047) | - | - | - | (105,563) | - | - | - | - |
| 20 | 411.10 | FAS 143 Accretion Expense | 241,122 | - | - | - | - | - | - | - | - | - |
| 21 | 411.8 | Gain on Sales of Emission Allowances | (471,379) | - | - | - | - | - | - | - | - | - |
| | | **Other Power Production Expense** | | | | | | | | | | |
| 22 | 546 | Operation Supervision & Engineering | 111,406 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | 547 | Fuel - **PPFAC Eligible** | 26,864,966 | - | - | - | - | - | - | - | - | - |
| 24 | 551 | Maintenance Supervision & Engineering | 4,687 | - | - | - | - | - | - | - | - | - |
| 25 | 552 | Maintenance of Structures | 11,568 | - | - | - | - | - | - | - | - | - |
| 26 | 553 | Maintenance of Generating and Electric Plant | 144,320 | - | - | - | - | - | - | - | - | - |
| 27 | 554 | Maintenance of Miscellaneous Other Power Generation Plant | 75,521 | - | - | - | - | - | - | - | - | - |
| 28 | 557 | Other Expenses | 7,423 | - | - | - | - | - | - | - | - | - |
| | | **Other Power Supply Expense** | | | | | | | | | | |
| 29 | 555 | Purchased Power - Demand - **PPFAC Eligible** | $ 30,633,600 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | 555 | Purchased Power - Energy - **PPFAC Eligible** | 40,035,094 | - | - | - | - | - | - | - | - | - |
| 31 | 556 | System Control and Load Dispatching | 2,188,934 | - | - | - | - | - | - | - | - | - |
| | | **Transmission Non-EHV (138kv & Below) Expense** | | | | | | | | | | |
| 32 | 560 | Operation Supervision & Engineering | $ 218,237 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | 561 & 561.1 - 561.8 | Load Dispatch & Various | 247,761 | - | - | - | - | - | - | - | - | - |
| 34 | 562 | Station Expenses | 14 | - | - | - | - | - | - | - | - | - |
| 35 | 563 | Overhead Line Expenses | 13 | - | - | - | - | - | - | - | - | - |
| 36 | 566 | Miscellaneous Transmission Expenses | 258,482 | - | - | - | - | (72,080) | - | - | - | - |
| 37 | 568 | Maintenance Supervision & Engineering | 188,959 | - | - | - | - | - | - | - | - | - |
| 38 | 569 & 569.1 - 569.3 | Maintenance of Structures & Computers (Hard & Software & Equip) | 31,223 | - | - | - | - | - | - | - | - | - |
| 39 | 570 | Maintenance of Station Equipment | 1,430,472 | - | - | - | - | (17,401) | - | - | - | - |
| 40 | 571 | Maintenance of Overhead Lines | 391,608 | - | - | - | - | - | - | - | - | - |
| 41 | 573 | Maintenance of Miscellaneous Transmission Plant | (3,170) | - | - | - | - | - | - | - | - | - |
| 42 | | **Transmission EHV (345kv & Above) Expense** | | | | | | | | | | |
| 43 | 560 | Operation Supervision & Engineering | 547,473 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 44 | 561 & 561.1 - 561.8 | Load Dispatch - Monitor & Operation Transmission System | 951,904 | - | - | - | - | - | - | - | - | - |
| 45 | 562 | Station Expenses | 5,186 | - | - | - | - | - | - | - | - | - |
| 46 | 563 | Overhead Line Expenses | 1,526 | - | - | - | - | - | - | - | - | - |
| 47 | 565 | Transmission of Electricity by Others - **PPFAC Eligible** | 4,771,517 | - | - | - | - | - | - | - | - | - |
| 48 | 566 | Miscellaneous Transmission Expenses | 242,986 | - | - | - | - | - | - | - | - | - |
| 49 | 567 | Rents | 433,517 | - | - | - | - | - | - | - | - | - |
| 50 | 568 | Maintenance Supervision & Engineering | 58,948 | - | - | - | - | - | - | - | - | - |
| 51 | 569 & 569.1 - 569.3 | Maintenance of Structures & Computers (Hard & Software & Equip) | 345,293 | - | - | - | - | - | - | - | - | - |
| 52 | 570 | Maintenance of Station Equipment | 1,309,338 | - | - | - | - | - | - | - | - | - |
| 53 | 571 | Maintenance of Overhead Lines | 502,738 | - | - | - | - | - | - | - | - | - |
| 54 | 573 | Maintenance of Miscellaneous Transmission Plant | 222,572 | - | - | - | - | - | - | - | - | - |

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Tucson Electric Power Company
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Test Year Ended December 31, 2006

Cost of Service
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SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

| LINE NO. | FERC ACCT | DESCRIPTION | (A) COMPANY AS FILED | (B) ADJ. NO. 1 SPRINGERVILLE UNIT 1 TESTIMONY-MDC | (C) ADJ. NO. 2 DEP/AMORT EXPENSES SCH. RLM-9 | (D) ADJ. NO. 3 INAPPROPRIATE EXPENSES SCH. RLM-10 | (E) ADJ. NO. 4 SERP TESTIMONY-RLM | (F) ADJ. NO. 5 INCENTIVE COMP. SCH. RLM-11 | (G) ADJ. NO. 6 RATE CASE EXPENSE TESTIMONY-RLM | (H) ADJ. NO. 7 PROPERTY TAX SCH. RLM-12 | (I) ADJ. NO. 8 O/H LINES MAINTENANCE SCH. RLM-13 | (J) ADJ. NO. 9 PENALTIES & FINES TESTIMONY-RLM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Distribution Expense** | | | | | | | | | | |
| 55 | 580 | Operation Supervision & Engineering | $ 2,342,158 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 56 | 581 | Load Dispatching | 234,186 | - | - | - | - | - | - | - | - | - |
| 57 | 582 | Station Expenses | 129,910 | - | - | - | - | - | - | - | - | - |
| 58 | 583 | Overhead Line Expenses | 712,968 | - | - | - | - | - | - | - | - | - |
| 59 | 584 | Underground Line Expenses | 6,935 | - | - | - | - | - | - | - | - | - |
| 60 | 585 | Street Lighting & Signal System Expenses | 114,826 | - | - | - | - | - | - | - | - | - |
| 61 | 586 | Meter Expenses | 773,201 | - | - | - | - | - | - | - | - | - |
| 62 | 587 | Customer Installations Expense | 204,569 | - | - | - | - | - | - | - | - | - |
| 63 | 588 | Miscellaneous Distribution Expenses | 9,109,574 | - | - | - | - | (174,456) | - | - | - | - |
| 64 | 589 | Rents | 297,011 | - | - | - | - | - | - | - | - | - |
| 65 | 590 | Maintenance Supervision & Engineering | 657,272 | - | - | - | - | - | - | - | - | - |
| 66 | 592 | Maintenance of Station Equipment | 1,581,845 | - | - | - | - | - | - | - | - | - |
| 67 | 593 | Maintenance of Overhead Lines | 1,831,514 | - | - | - | - | - | - | - | (126,584) | - |
| 68 | 594 | Maintenance of Underground Lines | 116,941 | - | - | - | - | - | - | - | - | - |
| 69 | 595 | Maintenance of Line Transformers | 581,610 | - | - | - | - | - | - | - | - | - |
| 70 | 596 | Maintenance of Street Lighting & Signal Systems | 1,676 | - | - | - | - | - | - | - | - | - |
| 71 | 597 | Maintenance of Meters | 119,505 | - | - | - | - | - | - | - | - | - |
| 72 | 598 | Maintenance of Miscellaneous Distribution Plant | 362,524 | - | - | - | - | (27,783) | - | - | - | - |
| 73 | 407.3 | Regulatory Asset Amortization | 11,863,806 | - | - | - | - | - | - | - | - | - |
| | | **Customer Account Expense** | | | | | | | | | | |
| 74 | 901 | Supervision | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 902 | Meter Reading Expenses | 3,057,311 | - | - | - | - | - | - | - | - | - |
| 75 | 903 | Customer Records & Collection Expenses | 13,038,115 | - | - | - | - | (100,172) | - | - | - | - |
| 76 | 904 | Uncollectible Accounts | 2,490,991 | - | - | - | - | - | - | - | - | - |
| 77 | 905 | Miscellaneous Customer Accounts Expenses | (31,254) | - | - | - | - | - | - | - | - | - |
| 78 | 908 | Customer Assistance Expenses | 22,188 | - | - | - | - | - | - | - | - | - |
| 79 | 909 | Informational and Instructional Advertising Expenses | 234,968 | - | - | - | - | - | - | - | - | - |
| 80 | 910 | Miscellaneous Customer Service & Informational Expenses | 18,298 | - | - | - | - | - | - | - | - | - |
| | | **Administrative and General Expense** | | | | | | | | | | |
| 81 | 920 | Administrative & General Salaries | 21,966,550 | $ (269,768) | $ - | $ - | $ - | $ (693,004) | $ - | $ - | $ - | $ - |
| 82 | 921 | Office Supplies & Expenses | 7,836,017 | (109,258) | - | (327,746) | - | - | - | - | - | (6,096) |
| 83 | 922 | Administrative Expenses Transferred - Credit | (8,495,252) | - | - | - | - | - | - | - | - | (982) |
| 84 | 923 | Outside Services Employed | 6,868,412 | (70,685) | - | (1,568) | - | - | - | - | - | (2,355) |
| 85 | 924 | Property Insurance | 2,469,577 | (195,540) | - | - | - | - | - | - | - | - |
| 86 | 925 | Injuries and Damages | 4,586,745 | (27,379) | - | - | - | - | - | - | - | - |
| 87 | 926 | Employee Pension & Benefits | 19,425,177 | (696,565) | - | - | (927,925) | - | - | - | - | - |
| 88 | 928 | Regulatory Commission Expenses | 441,957 | - | - | - | - | - | (112,500) | - | - | - |
| 89 | 929 | Duplicate Charges - Credit | (916,836) | - | - | - | - | - | - | - | - | - |
| 90 | 930.1 | General Advertising Expenses | 478,399 | - | - | (16,103) | - | - | - | - | - | - |
| 91 | 930.2 | Miscellaneous General Expenses | 9,600,842 | (13,036) | - | (168,315) | - | - | - | - | - | - |
| 92 | 931 | Rents | 660,232 | (5,947) | - | - | - | - | - | - | - | - |
| 93 | 935 | Maintenance of General Plant | 107,783 | - | - | - | - | (561) | - | - | - | - |
| 94 | | **Total Operation and Maintenance Expense** | $ 651,728,310 | $ (32,094,800) | $ - | $ (513,731) | $ (927,925) | $ (1,432,892) | $ (112,500) | $ - | $ (126,584) | $ (9,433) |
| | | **Depreciation & Amortization - All** | | | | | | | | | | |
| 95 | 403/404/406 | Intangible Plant | $ 6,647,388 | $ - | $ 22,658 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 96 | 403/404/406 | Other Production Plant | 31,859,979 | - | 3,555,902 | - | - | - | - | - | - | - |
| 97 | 403/404/406 | Transmission Plant | 19,451,883 | - | 5,174 | - | - | - | - | - | - | - |
| 98 | 403/404/406 | Distribution Plant | 19,525,254 | - | - | - | - | - | - | - | - | - |
| 99 | 403/404/406 | General Plant | 4,955,790 | - | 483,475 | - | - | - | - | - | - | - |
| 100 | | **Total Depreciation & Amortization - All** | $ 82,440,295 | $ - | $ 4,067,209 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | **Taxes Other Than Income Taxes** | | | | | | | | | | |
| 101 | 408 | Property Tax - Steam Production | $ 11,318,945 | $ - | $ - | $ - | $ - | $ - | $ - | $ (662,616) | $ - | $ - |
| 102 | 408 | Property Tax - Other Production | 1,329,464 | - | - | - | - | - | - | $ (77,827) | - | - |
| 103 | 408 | Property Tax - Transmission (EHV) | 2,224,427 | - | - | - | - | - | - | $ (130,219) | - | - |
| 104 | 408 | Property Tax - Transmission (Non-EHV) | 2,895,090 | - | - | - | - | - | - | $ (169,480) | - | - |
| 105 | 408 | Property Tax - Distribution | 12,983,459 | - | - | - | - | - | - | $ (760,058) | - | - |
| 106 | 408 | Business Activity Tax - Generation | 158,533 | - | - | - | - | - | - | - | - | - |
| 107 | 408 | Business Activity Tax - Transmission | 21,333 | - | - | - | - | - | - | - | - | - |
| 108 | 408 | Other (Including Payroll Taxes) | 4,899,431 | - | - | - | - | (92,486) | - | - | - | - |
| 109 | | **Total Taxes Other Than Income Taxes** | $ 35,830,682 | $ - | $ - | $ - | $ - | $ (92,486) | $ - | $ (1,800,201) | $ - | $ - |
| 110 | | **Total Income Taxes** | $ (12,260,463) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 111 | **Total Operating Expense** | | $ 757,738,824 | $ (32,094,900) | $ 4,067,209 | $ (513,731) | $ (927,925) | $ (1,525,378) | $ (112,500) | $ (1,800,201) | $ (126,584) | $ (9,433) |
| 112 | **OPERATING INCOME** | | $ 26,656,380 | $ 32,561,941 | $ (4,067,209) | $ 513,731 | $ 927,925 | $ 1,525,378 | $ 112,500 | $ 1,800,201 | $ 126,584 | $ 9,433 |

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

Cost of Service
Schedule RLM-8
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| LINE NO. | FERC ACCT | DESCRIPTION | (K) ADJ. NO. 10 LUNA PLANT O & M TESTIMONY-MDC | (L) ADJ. NO. 11 IMPLEMT'N COST REG. ASSET TESTIMONY-MDC | (M) ADJ. NO. 12 PAYROLL SCH. RLM-14 | (N) ADJ. NO. 13 PAYROLL TAX SCH. RLM-15 | (O) ADJ. NO. 14 RENEWABLE RESOURSES TESTIMONY-RLM | (P) ADJ. NO. 15 BAD DEBT TESTIMONY-MDC | (Q) ADJ. NO. 16 NAVAJO COAL TESTIMONY-MDC | (R) ADJ. NO. 17 CUSTOMER CARE AND BILLING SCH. RLM-16 | (S) ADJ. NO. 18 GAIN ON SALE OF SO2 ALLOWANCES TESTIMONY-MDC | (T) ADJ. NO. 19 EMPLOYEE RECOGNITION TESTIMONY-RLM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 440, 442, 444,445 | **Electric Retail Revenue** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2 | 446 | **Sales for Resale** | - | - | - | - | - | - | - | - | - | - |
| 3 | 447 | **Total Electric Retail Revenue** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | **Other Operating Revenue** | | | | | | | | | | |
| 4 | 451 | Miscellaneous Service Revenues | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 5 | 454 | Rent from Electric Property | - | - | - | - | - | - | - | - | - | - |
| 6 | 456 | Other Electric Revenues | - | - | - | - | - | - | - | - | - | - |
| 7 | | **Total Other Operating Revenue** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | **Total Operating Revenue** | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | **Steam Power Generation Expense** | | | | | | | | | | |
| 9 | 500 | Operation Supervision & Engineering | $ 543 | $ - | $ 1,143 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 10 | 501 | Fuel - **PPFAC Eligible** | - | - | 123 | - | - | - | (2,194,235) | - | - | - |
| 11 | 502 | Steam Expenses | - | - | 1,362 | - | - | - | - | - | - | - |
| 12 | 505 | Electric Expenses | - | - | 467 | - | - | - | - | - | - | - |
| 13 | 506 | Miscellaneous Steam Power Expenses | - | - | 356 | - | - | - | - | - | - | - |
| 14 | 507 | Rents | - | - | - | - | - | - | - | - | - | - |
| 15 | 510 | Maintenance Supervision & Engineering | - | - | 943 | - | - | - | - | - | - | - |
| 16 | 511 | Maintenance of Structures | - | - | 130 | - | - | - | - | - | - | - |
| 17 | 512 | Maintenance of Boiler Plant | - | - | 1,424 | - | - | - | - | - | - | - |
| 18 | 513 | Maintenance of Electric Plant | - | - | 264 | - | - | - | - | - | - | - |
| 19 | 514 | Maintenance Miscellaneous Steam Plant | - | - | 528 | - | - | - | - | - | - | - |
| 20 | 411.10 | FAS 143 Accretion Expense | 2,538 | - | - | - | - | - | - | - | - | - |
| 21 | 411.8 | Gain on Sales of Emission Allowances | - | - | - | - | - | - | - | - | (6,716,000) | - |
| | | **Other Power Production Expense** | | | | | | | | | | |
| 22 | 546 | Operation Supervision & Engineering | $ 1,727,358 | $ - | $ 80 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | 547 | Fuel - **PPFAC Eligible** | - | - | - | - | - | - | - | - | - | - |
| 24 | 551 | Maintenance Supervision & Engineering | - | - | - | - | - | - | - | - | - | - |
| 25 | 552 | Maintenance of Structures | - | - | - | - | - | - | - | - | - | - |
| 26 | 553 | Maintenance of Generating and Electric Plant | 27,609 | - | 19 | - | - | - | - | - | - | - |
| 27 | 554 | Maintenance of Miscellaneous Other Power Generation Plant | - | - | 7 | - | - | - | - | - | - | - |
| 28 | 557 | Other Expenses | - | - | - | - | - | - | - | - | - | - |
| | | **Other Power Supply Expense** | | | | | | | | | | |
| 29 | 555 | Purchased Power - Demand - **PPFAC Eligible** | $ (15,960,000) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | 555 | Purchased Power - Energy - **PPFAC Eligible** | - | - | - | - | - | - | - | - | - | - |
| 31 | 556 | System Control and Load Dispatching | 84,889 | - | 512 | - | - | - | - | - | - | - |
| | | **Transmission Non-EHV (138kv & Below) Expense** | | | | | | | | | | |
| 32 | 560 | Operation Supervision & Engineering | $ 5,746 | $ - | $ 212 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | 561 & 561.1 - 561.8 | Load Dispatch & Various | - | - | 284 | - | - | - | - | - | - | - |
| 34 | 562 | Station Expenses | - | - | 0 | - | - | - | - | - | - | - |
| 35 | 563 | Overhead Line Expenses | - | - | 0 | - | - | - | - | - | - | - |
| 36 | 566 | Miscellaneous Transmission Expenses | - | - | 20 | - | - | - | - | - | - | - |
| 37 | 568 | Maintenance Supervision & Engineering | - | - | 67 | - | - | - | - | - | - | - |
| 38 | 569 & 569.1 - 569.3 | Maintenance of Structures & Computers (Hard & Software & Equip) | - | - | 101 | - | - | - | - | - | - | - |
| 39 | 570 | Maintenance of Station Equipment | - | - | 447 | - | - | - | - | - | - | - |
| 40 | 571 | Maintenance of Overhead Lines | - | - | 63 | - | - | - | - | - | - | - |
| 41 | 573 | Maintenance of Miscellaneous Transmission Plant | - | - | 26 | - | - | - | - | - | - | - |
| 42 | | **Transmission EHV (345kv & Above) Expense** | | | | | | | | | | |
| 43 | 560 | Operation Supervision & Engineering | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 44 | 561 & 561.1 - 561.8 | Load Dispatch - Monitor & Operation Transmission System | 36,266 | - | - | - | - | - | - | - | - | - |
| 45 | 562 | Station Expenses | - | - | - | - | - | - | - | - | - | - |
| 46 | 563 | Overhead Line Expenses | - | - | - | - | - | - | - | - | - | - |
| 47 | 565 | Transmission of Electricity by Others - **PPFAC Eligible** | - | - | - | - | - | - | - | - | - | - |
| 48 | 566 | Miscellaneous Transmission Expenses | - | - | - | - | - | - | - | - | - | - |
| 49 | 567 | Rents | - | - | - | - | - | - | - | - | - | - |
| 50 | 568 | Maintenance Supervision & Engineering | - | - | - | - | - | - | - | - | - | - |
| 51 | 569 & 569.1 - 569.3 | Maintenance of Structures & Computers (Hard & Software & Equip) | - | - | - | - | - | - | - | - | - | - |
| 52 | 570 | Maintenance of Station Equipment | - | - | - | - | - | - | - | - | - | - |
| 53 | 571 | Maintenance of Overhead Lines | - | - | - | - | - | - | - | - | - | - |
| 54 | 573 | Maintenance of Miscellaneous Transmission Plant | - | - | - | - | - | - | - | - | - | - |

Continued On Page 4

| LINE NO. | FERC ACCT | DESCRIPTION | (K) ADJ. NO. 10 LUNA PLANT O & M TESTIMONY-MDC | (L) ADJ. NO. 11 IMPLEMT'N COST REG. ASSET TESTIMONY-MDC | (M) ADJ. NO. 12 PAYROLL SCH. RLM-14 | (N) ADJ. NO. 13 PAYROLL TAX SCH. RLM-15 | (O) ADJ. NO. 14 RENEWABLE RESOURSES TESTIMONY-RLM | (P) ADJ. NO. 15 BAD DEBT TESTIMONY-MDC | (Q) ADJ. NO. 16 NAVAJO COAL TESTIMONY-MDC | (R) ADJ. NO. 17 CUSTOMER CARE AND BILLING SCH. RLM-16 | (S) ADJ. NO. 18 GAIN ON SALE OF SO2 ALLOWANCES TESTIMONY-MDC | (T) ADJ. NO. 19 EMPLOYEE RECOGNITION TESTIMONY-RLM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Distribution Expense** | | | | | | | | | | |
| 55 | 580 | Operation Supervision & Engineering | $ - | $ - | $ 541 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 56 | 581 | Load Dispatching | - | - | 67 | - | - | - | - | - | - | - |
| 57 | 582 | Station Expenses | - | - | 24 | - | - | - | - | - | - | - |
| 58 | 583 | Overhead Line Expenses | - | - | 170 | - | - | - | - | - | - | - |
| 59 | 584 | Underground Line Expenses | - | - | 1 | - | - | - | - | - | - | - |
| 60 | 585 | Street Lighting & Signal System Expenses | - | - | 0 | - | - | - | - | - | - | - |
| 61 | 586 | Meter Expenses | - | - | 223 | - | - | - | - | - | - | - |
| 62 | 587 | Customer Installations Expense | - | - | 62 | - | - | - | - | - | - | - |
| 63 | 588 | Miscellaneous Distribution Expenses | - | - | 1,196 | - | - | - | - | - | - | - |
| 64 | 589 | Rents | - | - | - | - | - | - | - | - | - | - |
| 65 | 590 | Maintenance Supervision & Engineering | - | - | 177 | - | - | - | - | - | - | - |
| 66 | 592 | Maintenance of Station Equipment | - | - | 236 | - | - | - | - | - | - | - |
| 67 | 593 | Maintenance of Overhead Lines | - | - | 273 | - | - | - | - | - | - | - |
| 68 | 594 | Maintenance of Underground Lines | - | - | 9 | - | - | - | - | - | - | - |
| 69 | 595 | Maintenance of Line Transformers | - | - | 148 | - | - | - | - | - | - | - |
| 70 | 596 | Maintenance of Street Lighting & Signal Systems | - | - | 0 | - | - | - | - | - | - | - |
| 71 | 597 | Maintenance of Meters | - | - | 31 | - | - | - | - | - | - | - |
| 72 | 598 | Maintenance of Miscellaneous Distribution Plant | - | - | 38 | - | - | - | - | - | - | - |
| 73 | 407.3 | Regulatory Asset Amortization | - | (8,310,596) | - | - | - | - | - | - | - | - |
| | | **Customer Account Expense** | | | | | | | | | | |
| 74 | 901 | Supervision | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 902 | Meter Reading Expenses | - | - | - | - | - | - | - | - | - | - |
| 75 | 903 | Customer Records & Collection Expenses | - | - | 2,285 | - | - | - | - | (296,230) | - | - |
| 76 | 904 | Uncollectible Accounts | - | - | - | - | - | (520,078) | - | - | - | - |
| 77 | 905 | Miscellaneous Customer Accounts Expenses | - | - | - | - | - | - | - | - | - | - |
| 78 | 908 | Customer Assistance Expenses | - | - | 175 | - | - | - | - | - | - | - |
| 79 | 909 | Informational and Instructional Advertising Expenses | - | - | 22 | - | (16,768) | - | - | - | - | - |
| 80 | 910 | Miscellaneous Customer Service & Informational Expenses | - | - | - | - | - | - | - | - | - | - |
| | | **Administrative and General Expense** | | | | | | | | | | |
| 81 | 920 | Administrative & General Salaries | $ 312 | $ - | $ 4,747 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 82 | 921 | Office Supplies & Expenses | 32,973 | - | - | - | - | - | - | - | - | - |
| 83 | 922 | Administrative Expenses Transferred - Credit | - | - | - | - | - | - | - | - | - | - |
| 84 | 923 | Outside Services Employed | 52,181 | - | - | - | - | - | - | - | - | - |
| 85 | 924 | Property Insurance | 87,014 | - | - | - | - | - | - | - | - | - |
| 86 | 925 | Injuries and Damages | 11,798 | - | 229 | - | (6) | - | - | - | - | - |
| 87 | 926 | Employee Pension & Benefits | 26,950 | - | 255 | - | (2,013) | - | - | - | - | (76,125) |
| 88 | 928 | Regulatory Commission Expenses | - | - | - | - | - | - | - | - | - | - |
| 89 | 929 | Duplicate Charges - Credit | - | - | - | - | - | - | - | - | - | - |
| 90 | 930.1 | General Advertising Expenses | - | - | - | - | - | - | - | - | - | - |
| 91 | 930.2 | Miscellaneous General Expenses | - | - | 115 | - | - | - | - | - | - | - |
| 92 | 931 | Rents | - | - | - | - | - | - | - | - | - | - |
| 93 | 935 | Maintenance of General Plant | - | - | 29 | - | - | - | - | - | - | - |
| 94 | | **Total Operation and Maintenance Expense** | $ (13,863,823) | $ (8,310,596) | $ 19,651 | $ - | $ (18,785) | $ (520,078) | $ (2,194,235) | $ (296,230) | $ (6,716,000) | $ (76,125) |
| | | **Depreciation & Amortization - All** | | | | | | | | | | |
| 95 | 403/404/406 | Intangible Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 96 | 403/404/406 | Other Production Plant | - | - | - | - | - | - | - | - | - | - |
| 97 | 403/404/406 | Transmission Plant | - | - | - | - | - | - | - | - | - | - |
| 98 | 403/404/406 | Distribution Plant | - | - | - | - | - | - | - | - | - | - |
| 99 | 403/404/406 | General Plant | - | - | - | - | - | - | - | - | - | - |
| 100 | | **Total Depreciation & Amortization - All** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | **Taxes Other Than Income Taxes** | | | | | | | | | | |
| 101 | 408 | Property Tax - Steam Production | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 102 | 408 | Property Tax - Other Production | - | - | - | - | - | - | - | - | - | - |
| 103 | 408 | Property Tax - Transmission (EHV) | - | - | - | - | - | - | - | - | - | - |
| 104 | 408 | Property Tax - Transmission (Non-EHV) | - | - | - | - | - | - | - | - | - | - |
| 105 | 408 | Property Tax - Distribution | - | - | - | - | - | - | - | - | - | - |
| 106 | 408 | Business Activity Tax - Generation | - | - | - | - | - | - | - | - | - | - |
| 107 | 408 | Business Activity Tax - Transmission | - | - | - | - | - | - | - | - | - | - |
| 108 | 408 | Other (Including Payroll Taxes) | 7,575 | - | - | 2,669 | (489) | - | - | - | - | - |
| 109 | | **Total Taxes Other Than Income Taxes** | $ 7,575 | $ - | $ - | $ 2,669 | $ (489) | $ - | $ - | $ - | $ - | $ - |
| 110 | | **Total Income Taxes** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 111 | **Total Operating Expense** | | $ (13,856,248) | $ (8,310,596) | $ 19,651 | $ 2,669 | $ (19,274) | $ (520,078) | $ (2,194,235) | $ (296,230) | $ (6,716,000) | $ (76,125) |
| 112 | **OPERATING INCOME** | | $ 13,856,248 | $ 8,310,596 | $ (19,651) | $ (2,669) | $ 19,274 | $ 520,078 | $ 2,194,235 | $ 296,230 | $ 6,716,000 | $ 76,125 |

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

Cost of Service
Schedule RLM-8
Pages 5 & 6 of 6

| LINE NO. | FERC ACCT | DESCRIPTION | (U) ADJ. NO. 20 EMPLOYEE BENEFITS TESTIMONY-RLM | (V) ADJ. NO. 21 LIME USAGE COSTS TESTIMONY-MDC | (W) ADJ. NO. 22 SHORT-TERM SALES TESTIMONY-MDC | (X) ADJ. NO. 23 GENRT'G FAC. OPERATING LEASE TESTIMONY-MDC | (Y) ADJ. NO. 24 MISCELLANEOUS REVENUES TESTIMONY-MDC | (Z) ADJ. NO. 25 WHOLESALE TRADING ACT'Y TESTIMONY-MDC | (AA) ADJ. NO. 26 RATE CASE EXP. E-01933A-05-0650 TESTIMONY-MDC | (AB) ADJ. NO. 27 GAIN ON LAND SALES TESTIMONY-MDC | (AC) ADJ. NO. 28 INCOME TAX SCH. RLM-15 | (AD) RUCO AS ADJUSTED |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 440, 442, 444,445 | **Electric Retail Revenue** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 691,451,429 |
| 2 | 446 | **Sales for Resale** | - | - | 77,685,000 | - | - | 106,100,000 | - | - | - | 242,187,097 |
| 3 | 447 | **Total Electric Retail Revenue** | $ - | $ - | $ 77,685,000 | $ - | $ - | $ 106,100,000 | $ - | $ - | $ - | $ 933,638,526 |
| | | **Other Operating Revenue** | | | | | | | | | | |
| 4 | 451 | Miscellaneous Service Revenues | $ - | $ - | $ - | $ - | $ 1,161,265 | $ - | $ - | $ - | $ - | $ 4,972,036 |
| 5 | 454 | Rent from Electric Property | - | (598,676) | - | - | - | - | - | - | - | 9,814,967 |
| 6 | 456 | Other Electric Revenues | - | - | - | - | - | - | - | - | - | 20,884,206 |
| 7 | | **Total Other Operating Revenue** | $ - | $ (598,676) | $ - | $ - | $ 1,161,265 | $ - | $ - | $ - | $ - | $ 35,671,209 |
| 8 | **Total Operating Revenue** | | $ - | $ (598,676) | $ 77,685,000 | $ - | $ 1,161,265 | $ 106,100,000 | $ - | $ - | $ - | $ 969,309,734 |
| | | **Steam Power Generation Expense** | | | | | | | | | | |
| 9 | 500 | Operation Supervision & Engineering | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 6,847,192 |
| 10 | 501 | Fuel - PPFAC Eligible | - | - | 30,464,000 | (5,053,588) | - | - | - | - | - | 262,306,590 |
| 11 | 502 | Steam Expenses | - | (894,158) | - | - | - | - | - | - | - | 18,944,520 |
| 12 | 505 | Electric Expenses | - | - | - | - | - | - | - | - | - | 3,168,590 |
| 13 | 506 | Miscellaneous Steam Power Expenses | (930) | - | - | - | - | - | - | - | - | 5,807,224 |
| 14 | 507 | Rents | - | - | - | (4,353,842) | - | - | - | - | - | 67,835,047 |
| 15 | 510 | Maintenance Supervision & Engineering | - | - | - | - | - | - | - | - | - | 4,623,690 |
| 16 | 511 | Maintenance of Structures | - | - | - | - | - | - | - | - | - | 2,201,847 |
| 17 | 512 | Maintenance of Boiler Plant | - | - | - | - | - | - | - | - | - | 26,555,283 |
| 18 | 513 | Maintenance of Electric Plant | - | - | - | - | - | - | - | - | - | 6,609,819 |
| 19 | 514 | Maintenance Miscellaneous Steam Plant | - | - | - | - | - | - | - | - | - | 6,862,690 |
| 20 | 411.10 | FAS 143 Accretion Expense | - | - | - | - | - | - | - | - | - | 243,560 |
| 21 | 411.8 | Gain on Sales of Emission Allowances | - | - | - | - | - | - | - | - | - | (7,167,379) |
| | | **Other Power Production Expense** | | | | | | | | | | |
| 22 | 546 | Operation Supervision & Engineering | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,838,844 |
| 23 | 547 | Fuel - PPFAC Eligible | - | - | - | - | - | - | - | - | - | 26,864,966 |
| 24 | 551 | Maintenance Supervision & Engineering | - | - | - | - | - | - | - | - | - | 4,687 |
| 25 | 552 | Maintenance of Structures | - | - | - | - | - | - | - | - | - | 11,568 |
| 26 | 553 | Maintenance of Generating and Electric Plant | - | - | - | - | - | - | - | - | - | 171,948 |
| 27 | 554 | Maintenance of Miscellaneous Other Power Generation Plant | - | - | - | - | - | - | - | - | - | 75,526 |
| 28 | 557 | Other Expenses | - | - | - | - | - | - | - | - | - | 7,423 |
| | | **Other Power Supply Expense** | | | | | | | | | | |
| 29 | 555 | Purchased Power - Demand - PPFAC Eligible | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 14,673,600 |
| 30 | 555 | Purchased Power - Energy - PPFAC Eligible | - | - | 21,862,000 | - | - | 104,381,000 | - | - | - | 166,378,094 |
| 31 | 556 | System Control and Load Dispatching | - | - | - | - | - | - | - | - | - | 2,274,335 |
| | | **Transmission Non-EHV (138kv & Below) Expense** | | | | | | | | | | |
| 32 | 560 | Operation Supervision & Engineering | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 224,195 |
| 33 | 561 & 561.1 - 561.8 | Load Dispatch & Various | - | - | - | - | - | - | - | - | - | 248,045 |
| 34 | 562 | Station Expenses | - | - | - | - | - | - | - | - | - | 14 |
| 35 | 563 | Overhead Line Expenses | - | - | - | - | - | - | - | - | - | 13 |
| 36 | 566 | Miscellaneous Transmission Expenses | - | - | - | - | - | - | - | - | - | 166,422 |
| 37 | 568 | Maintenance Supervision & Engineering | - | - | - | - | - | - | - | - | - | 189,026 |
| 38 | 569 & 569.1 - 569.3 | Maintenance of Structures & Computers (Hard & Software & Equip) | - | - | - | - | - | - | - | - | - | 31,324 |
| 39 | 570 | Maintenance of Station Equipment | - | - | - | - | - | - | - | - | - | 1,413,518 |
| 40 | 571 | Maintenance of Overhead Lines | - | - | - | - | - | - | - | - | - | 391,671 |
| 41 | 573 | Maintenance of Miscellaneous Transmission Plant | - | - | - | - | - | - | - | - | - | (3,143) |
| 42 | | **Transmission EHV (345kv & Above) Expense** | | | | | | | | | | |
| 43 | 560 | Operation Supervision & Engineering | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 547,473 |
| 44 | 561 & 561.1 - 561.8 | Load Dispatch - Monitor & Operation Transmission System | - | - | - | - | - | - | - | - | - | 988,170 |
| 45 | 562 | Station Expenses | - | - | - | - | - | - | - | - | - | 5,186 |
| 46 | 563 | Overhead Line Expenses | - | - | - | - | - | - | - | - | - | 1,528 |
| 47 | 565 | Transmission of Electricity by Others - PPFAC Eligible | - | - | - | - | - | - | - | - | - | 4,771,517 |
| 48 | 566 | Miscellaneous Transmission Expenses | - | - | - | - | - | - | - | - | - | 242,986 |
| 49 | 567 | Rents | - | - | - | - | - | - | - | - | - | 433,517 |
| 50 | 568 | Maintenance Supervision & Engineering | - | - | - | - | - | - | - | - | - | 58,948 |
| 51 | 569 & 569.1 - 569.3 | Maintenance of Structures & Computers (Hard & Software & Equip) | - | - | - | - | - | - | - | - | - | 345,293 |
| 52 | 570 | Maintenance of Station Equipment | - | - | - | - | - | - | - | - | - | 1,309,338 |
| 53 | 571 | Maintenance of Overhead Lines | - | - | - | - | - | - | - | - | - | 502,738 |
| 54 | 573 | Maintenance of Miscellaneous Transmission Plant | - | - | - | - | - | - | - | - | - | 222,572 |

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Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

Cost of Service
Schedule RLM-6
Pages 5 & 6 of 6

| LINE NO. | FERC ACC'T | DESCRIPTION | (U) ADJ. NO. 20 EMPLOYEE BENEFITS TESTIMONY-RLM | (V) ADJ. NO. 21 LIME USAGE COSTS TESTIMONY-MDC | (W) ADJ. NO. 22 SHORT-TERM SALES TESTIMONY-MDC | (X) ADJ. NO. 23 GENRT'G FAC. OPERATING LEASE TESTIMONY-MDC | (Y) ADJ. NO. 24 MISCELLANEOUS REVENUES TESTIMONY-MDC | (Z) ADJ. NO. 25 WHOLESALE TRADING ACT'Y TESTIMONY-MDC | (AA) ADJ. NO. 26 RATE CASE EXP. E-01933A-05-0650 TESTIMONY-MDC | (AB) ADJ. NO. 27 GAIN ON LAND SALES TESTIMONY-MDC | (AC) ADJ. NO. 28 INCOME TAX SCH. RLM-15 | (AD) RUCO AS ADJUSTED |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Distribution Expense** | | | | | | | | | | |
| 55 | 580 | Operation Supervision & Engineering | $ (7,868) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,334,831 |
| 56 | 581 | Load Dispatching | - | - | - | - | - | - | - | - | - | 234,253 |
| 57 | 582 | Station Expenses | - | - | - | - | - | - | - | - | - | 129,935 |
| 58 | 583 | Overhead Line Expenses | - | - | - | - | - | - | - | - | - | 713,138 |
| 59 | 584 | Underground Line Expenses | - | - | - | - | - | - | - | - | - | 6,936 |
| 60 | 585 | Street Lighting & Signal System Expenses | - | - | - | - | - | - | - | - | - | 114,926 |
| 61 | 586 | Meter Expenses | (818) | - | - | - | - | - | - | - | - | 772,606 |
| 62 | 587 | Customer Installations Expense | - | - | - | - | - | - | - | - | - | 204,631 |
| 63 | 588 | Miscellaneous Distribution Expenses | (4,038) | - | - | - | - | - | - | - | - | 8,932,276 |
| 64 | 589 | Rents | - | - | - | - | - | - | - | - | - | 297,011 |
| 65 | 590 | Maintenance Supervision & Engineering | - | - | - | - | - | - | - | - | - | 657,450 |
| 66 | 592 | Maintenance of Station Equipment | - | - | - | - | - | - | - | - | - | 1,582,081 |
| 67 | 593 | Maintenance of Overhead Lines | - | - | - | - | - | - | - | - | - | 1,705,204 |
| 68 | 594 | Maintenance of Underground Lines | - | - | - | - | - | - | - | - | - | 116,951 |
| 69 | 595 | Maintenance of Line Transformers | - | - | - | - | - | - | - | - | - | 581,758 |
| 70 | 596 | Maintenance of Street Lighting & Signal Systems | - | - | - | - | - | - | - | - | - | 1,676 |
| 71 | 597 | Maintenance of Meters | (700) | - | - | - | - | - | - | - | - | 118,836 |
| 72 | 598 | Maintenance of Miscellaneous Distribution Plant | - | - | - | - | - | - | - | - | - | 334,779 |
| 73 | 407.3 | Regulatory Asset Amortization | - | - | - | - | - | - | - | - | - | 3,553,210 |
| | | **Customer Account Expense** | | | | | | | | | | |
| 74 | 901 | Supervision | $ (8,812) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (8,812) |
| | 902 | Meter Reading Expenses | - | - | - | - | - | - | - | - | - | 3,057,311 |
| 75 | 903 | Customer Records & Collection Expenses | - | - | - | - | - | - | - | - | - | 12,643,989 |
| 76 | 904 | Uncollectible Accounts | - | - | - | - | - | - | - | - | - | 1,970,913 |
| 77 | 905 | Miscellaneous Customer Accounts Expenses | - | - | - | - | - | - | - | - | - | (31,254) |
| 78 | 908 | Customer Assistance Expenses | - | - | - | - | - | - | - | - | - | 22,363 |
| 79 | 909 | Informational and Instructional Advertising Expenses | - | - | - | - | - | - | - | - | - | 218,223 |
| 80 | 910 | Miscellaneous Customer Service & Informational Expenses | - | - | - | - | - | - | - | - | - | 18,298 |
| | | **Administrative and General Expense** | | | | | | | | | | |
| 81 | 920 | Administrative & General Salaries | $ - | $ - | $ - | $ - | $ - | $ - | $ (34,978) | $ - | $ - | $ 20,953,860 |
| 82 | 921 | Office Supplies & Expenses | - | - | - | - | - | - | (10,218) | - | - | 7,415,673 |
| 83 | 922 | Administrative Expenses Transferred - Credit | - | - | - | - | - | - | - | - | - | (8,496,234) |
| 84 | 923 | Outside Services Employed | - | - | - | - | - | - | (287,307) | - | - | 6,558,678 |
| 85 | 924 | Property Insurance | - | - | - | - | - | - | - | - | - | 2,361,051 |
| 86 | 925 | Injuries and Damages | - | - | - | - | - | - | (23) | - | - | 4,571,364 |
| 87 | 926 | Employee Pension & Benefits | - | - | - | - | - | - | (7,785) | - | - | 17,741,969 |
| 88 | 928 | Regulatory Commission Expenses | - | - | - | - | - | - | - | - | - | 329,457 |
| 89 | 929 | Duplicate Charges - Credit | - | - | - | - | - | - | - | - | - | (916,836) |
| 90 | 930.1 | General Advertising Expenses | - | - | - | - | - | - | - | - | - | 462,296 |
| 91 | 930.2 | Miscellaneous General Expenses | - | - | - | - | - | - | (18,907) | - | - | 9,400,699 |
| 92 | 931 | Rents | - | - | - | - | - | - | - | - | - | 654,285 |
| 93 | 935 | Maintenance of General Plant | - | - | - | - | - | - | - | - | - | 107,250 |
| 94 | | **Total Operation and Maintenance Expense** | $ (23,165) | $ (894,158) | $ 52,426,000 | $ (9,407,430) | $ - | $ 104,381,000 | $ (359,218) | $ - | $ - | $ 730,657,154 |
| | | **Depreciation & Amortization - All** | | | | | | | | | | |
| 95 | 403/404/406 | Intangible Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (254,740) | $ - | $ 6,415,306 |
| 96 | 403/404/406 | Other Production Plant | - | - | - | - | - | - | - | - | - | 35,415,881 |
| 97 | 403/404/406 | Transmission Plant | - | - | - | - | - | - | - | - | - | 19,457,058 |
| 98 | 403/404/406 | Distribution Plant | - | - | - | - | - | - | - | - | - | 19,525,254 |
| 99 | 403/404/406 | General Plant | - | - | - | - | - | - | - | - | - | 5,439,265 |
| 100 | | **Total Depreciation & Amortization - All** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (254,740) | $ - | $ 86,252,764 |
| | | **Taxes Other Than Income Taxes** | | | | | | | | | | |
| 101 | 408 | Property Tax - Steam Production | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 10,656,329 |
| 102 | 408 | Property Tax - Other Production | - | - | - | - | - | - | - | - | - | 1,251,636 |
| 103 | 408 | Property Tax - Transmission (EHV) | - | - | - | - | - | - | - | - | - | 2,094,208 |
| 104 | 408 | Property Tax - Transmission (Non-EHV) | - | - | - | - | - | - | - | - | - | 2,725,610 |
| 105 | 408 | Property Tax - Distribution | - | - | - | - | - | - | - | - | - | 12,223,401 |
| 106 | 408 | Business Activity Tax - Generation | - | - | - | - | - | - | - | - | - | 158,533 |
| 107 | 408 | Business Activity Tax - Transmission | - | - | - | - | - | - | - | - | - | 21,333 |
| 108 | 408 | Other (Including Payroll Taxes) | - | - | - | - | - | - | (1,867) | - | - | 4,814,853 |
| 109 | | **Total Taxes Other Than Income Taxes** | $ - | $ - | $ - | $ - | $ - | $ - | $ (1,867) | $ - | $ - | $ 33,945,904 |
| 110 | | **Total Income Taxes** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 111 | **Total Operating Expense** | | $ (23,165) | $ (894,158) | $ 52,426,000 | $ (9,407,430) | $ - | $ 104,381,000 | $ (361,085) | $ (254,740) | $ - | $ 850,855,921 |
| 112 | **OPERATING INCOME** | | $ 23,165 | $ 295,482 | $ 25,259,000 | $ 9,407,430 | $ 1,161,265 | $ 1,719,000 | $ 361,085 | $ 254,740 | $ - | $ 118,453,913 |

Tucson Electric Power Company
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Cost of Service
Schedule RLM-9
Pages 1 & 2 of 2

**OPERATING INCOME ADJUSTMENT NO. 2**
**TEST-YEAR DEPRECIATION EXPENSE ON GROSS PLANT IN SERVICE**

| LINE NO. | ACCT. NO. | DESCRIPTION | (A) RUCO TOTAL PLANT AS ADJT'D | (B) TEP PRO'D RATE | (C) RUCO DEP. EXP. | (D) COMPANY DEP. EXP. | (E) DIFFERENCE |
|---|---|---|---|---|---|---|---|
| | | INTANGIBLE PLANT | | | | | |
| 1 | 301 | Organization | $ 29,362 | 0.00% | $ - | $ - | |
| 2 | 302 | Franchises and Consents | 147,884 | 0.00% | - | - | |
| 3 | 303 | Miscellaneous Intangible Plant | 68,997,310 | 9.67% | 6,670,046 | 6,647,388 | |
| 4 | | TOTAL Intangible Plant | $ 69,174,556 | | $ 6,670,046 | $ 6,647,388 | $ 22,658 |
| | | PRODUCTION PLANT | | | | | |
| | | Steam Production Plant | | | | | |
| 5 | 310 | Land and Land Rights | $ 5,878,540 | 2.49% | $ 146,650 | $ 79,060 | |
| 6 | 311 | Structures and Improvements | 121,134,420 | 3.61% | 4,378,343 | 3,588,351 | |
| 7 | 312 | Boiler Plant Equipment | 707,073,200 | 2.44% | 17,231,711 | 16,142,455 | |
| 8 | 313 | Engines and Engine-Driven Generators | - | | - | - | |
| 9 | 314 | Turbogenerator Units | 231,204,768 | 3.29% | 7,606,235 | 7,195,383 | |
| 10 | 315 | Accessory Electric Equipment | 82,685,481 | 2.93% | 2,426,482 | 2,396,234 | |
| 11 | 316 | Misc. Power Plant Equipment | 19,877,558 | 2.98% | 592,807 | 567,729 | |
| 12 | 317 | Asset Retm't Costs for Steam Production | 366,915 | 3.15% | 11,558 | 10,840 | |
| 13 | 114 | San Juan Acquisition Adjustment | 3,124,669 | 3.73% | 116,655 | 116,655 | |
| 14 | | TOTAL Steam Plant | $ 1,171,345,551 | | $ 32,510,440 | $ 30,096,707 | $ 2,413,733 |
| | | Other Plant | | | | | |
| 15 | 340 | Land and Land Rights | $ 1,928,015 | 0.00% | $ - | $ - | |
| 16 | 341 | Structures and Improvements | 14,200,470 | 2.40% | 340,537 | 32,616 | |
| 17 | 342 | Fuel Holders, Products, and Accessories | 12,595,292 | 2.44% | 307,288 | 28,420 | |
| 18 | 343 | Prime Movers | 354,047 | 5.19% | 18,389 | 18,389 | |
| 19 | 344 | Generators | 78,477,670 | 2.88% | 2,256,302 | 1,807,155 | |
| 20 | 345 | Accessory Electric Equipment | 4,475,217 | 2.26% | 101,013 | 101,013 | |
| 21 | 346 | Misc. Power Plant Equipment | 8,385,479 | 1.45% | 121,246 | 15,013 | |
| 22 | | TOTAL Other Plant | $ 120,416,190 | | $ 3,144,775 | $ 2,002,606 | $ 1,142,169 |
| 23 | | TOTAL Production Plant | $ 1,291,761,741 | | $ 35,655,215 | $ 32,099,313 | $ 3,555,902 |
| | | TRANSMISSION PLANT | | | | | |
| 24 | 350 | Land and Land Rights | $ 10,785,048 | 3.46% | $ 372,681 | $ 372,281 | |
| 25 | 352 | Structures and Improvements | 7,634,167 | 3.46% | 263,801 | 263,731 | |
| 26 | 353 | Station Equipment | 124,499,472 | 3.46% | 4,302,116 | 4,296,095 | |
| 27 | 354 | Towers and Fixtures | 9,843,590 | 3.46% | 340,148 | 340,057 | |
| 28 | 355 | Poles and Fixtures | 18,675,438 | 3.46% | 645,335 | 645,163 | |
| 29 | 356 | Overhead Conductors and Devices | 16,703,460 | 3.46% | 577,193 | 577,039 | |
| 30 | | TOTAL Transmission Non-EHV | $ 188,141,175 | | $ 6,501,274 | $ 6,494,366 | $ 6,908 |
| 31 | 350 | Land and Land Rights | $ 15,037,219 | 3.46% | $ 519,616 | $ 519,777 | |
| 32 | 352 | Structures and Improvements | 10,080,213 | 3.46% | 348,325 | 348,232 | |
| 33 | 353 | Station Equipment | 134,192,652 | 3.46% | 4,637,067 | 4,640,702 | |
| 34 | 354 | Towers and Fixtures | 145,810,705 | 3.46% | 5,038,532 | 5,037,187 | |
| 35 | 355 | Poles and Fixtures | 1,341,221 | 3.46% | 46,346 | 46,334 | |
| 36 | 356 | Overhead Conductors and Devices | 66,469,318 | 3.46% | 2,296,867 | 2,296,254 | |
| 37 | 359 | Roads & Trails | 4,658,153 | 2.00% | 93,163 | 93,163 | |
| 38 | | TOTAL Transmission EHV | $ 377,589,481 | | $ 12,979,915 | $ 12,981,649 | $ (1,734) |
| 39 | | TOTAL Transmission Plant | $ 565,730,656 | | $ 19,481,189 | $ 19,476,015 | $ 5,174 |

**OPERATING INCOME ADJUSTMENT NO. 2**
**TEST-YEAR DEPRECIATION EXPENSE ON GROSS PLANT IN SERVICE**

| LINE NO. | ACCT. NO. | DESCRIPTION | (A) RUCO TOTAL PLANT AS ADJT'D | (B) TEP PRO'D RATE | (C) RUCO DEP. EXP. | (D) COMPANY DEP. EXP. | (E) DIFFERENCE |
|---|---|---|---|---|---|---|---|
| | | DISTRIBUTION PLANT | | | | | |
| 40 | 360 | Land and Land Rights | $ 9,858,745 | 1.16% | $ 114,276 | $ 114,276 | |
| 41 | 361 | Structures and Improvements | 6,282,094 | 1.63% | 102,398 | 102,398 | |
| 42 | 362 | Station Equipment | 95,451,660 | 1.46% | 1,393,594 | 1,393,594 | |
| 43 | 364 | Poles, Towers, and Fixtures | 112,985,358 | 1.63% | 1,841,661 | 1,841,661 | |
| 44 | 365 | Overhead Conductors and Devices | 106,758,542 | 1.47% | 1,569,351 | 1,569,351 | |
| 45 | 366 | Underground Conduit | 49,342,484 | 1.42% | 700,663 | 700,663 | |
| 46 | 367 | Underground Conductors and Devices | 213,374,544 | 1.89% | 4,032,779 | 4,032,779 | |
| 47 | 368 | Line Transformers | 203,129,296 | 2.26% | 4,593,451 | 4,593,451 | |
| 48 | 369 | Services | 92,019,762 | 1.52% | 1,394,698 | 1,394,698 | |
| 49 | 370 | Meters | 32,881,789 | 2.99% | 983,165 | 983,165 | |
| 50 | 371 | Installations on Customer Premises | - | | - | - | |
| 51 | 373 | Street Lighting and Signal Systems | 9,334,416 | 1.74% | 162,419 | 162,419 | |
| 52 | 374 | Asset Retirement Obligation | 216,459 | 2.97% | 6,429 | 6,429 | |
| 53 | | TOTAL Distribution Plant | $ 931,635,149 | | $ 16,894,884 | $ 16,894,884 | $ - |
| | | GENERAL PLANT | | | | | |
| 54 | 389 | Land and Land Rights | $ 302,740 | 0.00% | $ - | $ - | |
| 55 | 390 | Structures and Improvements | 35,424,469 | 3.54% | 1,254,795 | 1,251,512 | |
| 56 | 391 | Office Furniture and Equipment | 26,130,664 | 10.25% | 2,677,957 | 2,568,009 | |
| 57 | 392 | Transportation Equipment | 36,960,886 | 5.98% | 2,211,987 | 2,211,987 | |
| 58 | 393 | Stores Equipment | 988,421 | 6.67% | 65,927 | 52,513 | |
| 59 | 394 | Tools, Shop and Garage Equipment | 6,144,619 | 5.89% | 361,919 | 265,430 | |
| 60 | 395 | Laboratory Equipment | 4,273,434 | 5.89% | 251,706 | 213,183 | |
| 61 | 396 | Power Operated Equipment | 9,674,674 | 4.19% | 405,369 | 308,740 | |
| 62 | 397 | Communication Equipment | 29,835,899 | 3.71% | 1,106,912 | 1,079,515 | |
| 63 | 398 | Miscellaneous Equipment | 4,582,190 | 5.00% | 229,109 | 131,316 | |
| 64 | | TOTAL General Plant | $ 154,317,996 | | $ 8,565,680 | $ 8,082,205 | $ 483,475 |
| 65 | | SUB-TOTALS | $ 3,012,620,098 | | $ 87,267,014 | $ 83,199,805 | $ 4,067,209 |
| 66 | | Reconcile GPIS - WP"s To B-2 | $ 9,400,488 | | | | |
| 67 | | TOTALS | $ 3,022,020,586 | | | | |
| 68 | | Net Negative Salvage Distrubution (TEP Response To RUCO DR 2.13) | | | 2,603,350 3 | 2,603,350 3 | |
| 69 | | GRAND TOTAL | | | $ 89,870,367 | $ 85,803,158 | |
| 70 | | Company As Filed | | | $ 85,803,158 | $ 85,803,158 | |
| 71 | | Difference | | | $ 4,067,209 | | |
| 72 | | RUCO Adjustment (See RLM-8, Pages 1 & 2, Col. (C)) | | | $ 4,067,209 | | |

References:
- Column (A): Schedule RLM-5, Column (I)
- Column (B): Composite Rates Calculated From Company Response To RUCO DR 2.13
- Column (C): Column (A) X Column (B)
- Column (D): Company's Response To RUCO DR 2.13
- Column (E): Column (C) - Column (D)

Tucson Electric Power Company
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**OPERATING INCOME ADJUSTMENT NO. 3**
**RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES**

| LINE NO. | DESCRIPTION | | (A) AMOUNT |
|---|---|---|---|
| | Expenses Removed | | |
| 1 | Account 921 - A & G Expense - Office Supplies: | RUCO Workpapers - Revised Exhibit A 921 | $ (327,746) |
| 2 | Account 923 - A & G Expense - Outside Services Employed: | RUCO Workpapers - Revised Exhibit A 923 | (1,568) |
| 3 | Account 930.1 - A & G Expense - Miscellaneous General Expenses: | RUCO Workpapers - Revised Exhibit A 930.1 | (16,103) |
| 4 | Account 930.2 - A & G Expense - Miscellaneous General Expenses: | RUCO Workpapers - Revised Exhibit A 930.2 | (168,315) |
| 5 | Total Expenses Removec | Sum Of Lines 1 Thru 4 | $ (513,731) |
| 6 | RUCO Adjustment (See RLM-8, Pages 1 & 2, Col. (D) For Distribution | Line 7 | $ (513,731) |

Tucson Electric Power Company
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Cost of Service
Schedule RLM-11


**OPERATING INCOME ADJUSTMENT NO. 5**
**INCENTIVE COMPENSATION**

| LINE NO. | ACCT NO. | DESCRIPTION | (A) COMPANY DISTRIBUTION OF INC COMP ADJ'MENT | (B) ALLOCATION FACTOR | (C) RUCO DISTRIBUTION OF INC COMP ADJ'MENT |
|---|---|---|---|---|---|
| 1 | 506 | Miscellaneous Steam Power Expenses | $ 164,184 | 16.88% | $ (241,872) |
| 2 | 566 | Miscellaneous Transmission Expenses | 48,928 | 5.03% | (72,080) |
| 3 | 588 | Miscellaneous Distribution Expenses | 118,422 | 12.18% | (174,456) |
| 4 | 903 | Customer Records & Collection Expenses | 67,997 | 6.99% | (100,172) |
| 5 | 920 | Administrative & General Salaries | 470,415 | 48.36% | (693,004) |
| 6 | 514 | Maintenance Miscellaneous Steam Plant | 71,657 | 7.37% | (105,563) |
| 7 | 570 | Maintenance of Station Equipment | 11,812 | 1.21% | (17,401) |
| 8 | 598 | Maintenance of Miscellaneous Distribution Plant | 18,859 | 1.94% | (27,783) |
| 9 | 935 | Maintenance of General Plant | 381 | 0.04% | (561) |
| 10 | | SUB-TOTALS | $ 972,655 | 100.00% | $ (1,432,892) |
| 11 | 408 | FICA Taxes | | | $ (92,486) |
| 12 | | TOTALS | | | $ (1,525,378) |

**NOTE:**

RUCO Determination Of The Test-Year Incentive Compensation Payroll And FICA Taxes Expense Level:

| | | REFERENCE | PAYROLL | FICA TAXES |
|---|---|---|---|---|
| | STEP ONE: Restate Expense From 4-Year Average To Test Year Actual Level | | | |
| 13 | Adjusted TY Level Of Payroll And FICA Taxes (4-Yr Average) | Company Workpapers | $ 3,838,440 | $ 288,098 |
| 14 | Actual Test-Year Level Of Payroll And FICA Taxes | Company Workpapers | $ 4,811,096 | $ 391,224 |
| 15 | RUCO Adjustment To Adhere To Historical TY Principle | Line 14 - Line13 | $ 972,656 | $ 103,126 |
| | STEP TWO: Split Expense On A 50/50 Basis | | | |
| 16 | Company Test-Year Level Of Payroll And FICA Taxes | Company Workpapers | $ 4,811,096 | $ 391,224 |
| 17 | RUCO Adjustment To Split Expense On A 50/50 Basis | 50% Of Line 16 | $ (2,405,548) | $ (195,612) |
| 18 | RUCO Adjusted Expense (See Col. (C), Lines 10 & 11 | Sum Lines 15 & 17 | $ (1,432,892) | $ (92,486) |
| 19 | RUCO Adjustment (See RLM-8, Pages 1 & 2, Column (F)) | Sum Line 18, Col.'s (B) & (C) | | $ (1,525,378) |

References:

Column (A): Company Workpapers
Column (B): Individual Account Allocation Based On Percentage Of Each FERC Account To Total
Column (C): RUCO Adjustment To Incentive Compensation Allocated By Allocation Factors In Column (B)

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Cost of Service
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**OPERATING INCOME ADJUSTMENT NO. 7**
**PROPERTY TAX COMPUTATION**

| LINE NO. | DESCRIPTION | (A) | (B) | (C) |
|---|---|---|---|---|
| | Calculation Of The Company's Full Cash Value: | | | |
| 1 | Net Plant In Service (RLM-4, Column (H), Line 3) | | | $ 1,334,462,452 |
| 2 | Rate Base Reconcillation (Company Response TO RUCO DR 10.1) | $ (146,690,957) | | |
| 3 | RUCO Reversal Of OCRB - Springerville Unit 1 Land And Land Rights | (2,246,355) | | |
| 4 | RUCO Reversal Of Acc. Dep. - Springerville Unit 1 Intangibles | 5,258,018 | | |
| 5 | RUCO Reversal Of Acc. Dep. - AZ Gener'n, Intgb's, Ld Rghts & Gen Plt | - | | |
| 6 | RUCO Reversal Of OCRB - 345 KV Line Luna Power Plant To El Paso | 1,345,024 | | |
| 7 | RUCO Reversal Of Acc. Dep. - 345 KV Line Luna Power Plt To El Paso | (805,135) | | |
| 8 | TOTAL RUCO Adjustment Associated With Rate Base Adjustments (Sum Lns 2 Thru 7) | | $ (143,139,405) | |
| 9 | Licensed Transportation (Company Workpapers) | | (12,064,536) | |
| 10 | Land Cost And Rights (Company Workpapers) | | (12,077,452) | |
| 11 | Environmental Property (Company Workpapers) | | (182,446,282) | |
| 12 | Net Book Value Of Generation | | (442,581,696) | |
| 13 | Full Cash Value Of Generation | | 432,635,872 | |
| 14 | Land FCV Per ADOR (Company Workpapers) | | 12,821,624 | |
| 15 | Material And Supplies (Company Workpapers) | | 17,323,223 | |
| 16 | COMPANY'S FULL CASH VALUE (Sum Of Lines 1 Thru 15) | | | $ 1,004,933,800 |
| | Calculation Of The Company's Tax Liability: | | | |
| 17 | Assessment Ratio (Per House Bill 2779) | | 23.0% | |
| 18 | Assessed Value (Line 16 X Line 17) | | $ 231,134,774 | |
| 19 | Average Tax Rate (Company Workpapers) | | 10.66% | |
| 20 | PROPERTY TAX Excluding Environmental Property (Line 18 X Line 19) | | | $ 24,630,380 |
| 21 | Environmental Property (Line 11) | | $ 182,446,282 | |
| 22 | Statutory FCV Adjustment (Company Workpapers) | | 50.0% | |
| 23 | Environmental Property FVC (Line21 X Line 22) | | $ 91,223,141 | |
| 24 | Asessment Ratio (Line 17) | | 23.0% | |
| 25 | Taxable Value (Line 23 X Line 24) | | $ 20,981,322 | |
| 26 | Average Tax Rate (Company Workpapers) | | 10.66% | |
| 27 | PROPERTY TAX On Environmental Property (Line 25 X Line 26) | | | $ 2,235,830 |
| 28 | Land Held For Future Use In Rate Base | | $ 1,140,033 | |
| 29 | Asessment Ratio (Company Workpapers) | | 16.0% | |
| 30 | Taxable Value (Line 28 X Line 29) | | $ 182,405 | |
| 31 | Average Tax Rate (Company Workpapers) | | 10.66% | |
| 32 | PROPERTY TAX On Land Held For Future Use (Line 30 X Line 31) | | | $ 19,438 |
| 33 | COMPANY'S ARIZONA PROPERTY TAX LIABILITY (Sum Of Lines 20, 27 & 32) | | | $ 26,885,647 |
| 34 | COMPANY'S NEW MEXICO PROPERTY TAX LIABILITY (Company Workpapers) | | | 2,065,536 |
| 35 | Rounding | | | 1 |
| 36 | COMPANY PROPERTY TAX LIABILITY (Sum Of Lines 33 Thru 35) | | | $ 28,951,184 |
| 37 | Total Test Year Adjusted Property Tax Expense Per Company's Filing | | $ 30,751,385 | |
| 38 | Increase In Property Tax Expense (Line 36 - Line 37 | | $ (1,800,201) | |

| LINE NO. | Distribution Of Property Tax Adjustment | COMPANY WORKPAPERS | ALLOCATION FACTOR | RUCO ALLOCATION | |
|---|---|---|---|---|---|
| 39 | Steam Production | $ 11,318,945 | 36.81% | $ (662,616) | |
| 40 | Other Production | 1,329,464 | 4.32% | (77,827) | |
| 41 | Transmission (EHV) | 2,224,427 | 7.23% | (130,219) | |
| 42 | Transmission ( Non-EHV) | 2,895,090 | 9.41% | (169,480) | |
| 43 | Distribution | 12,983,459 | 42.22% | (760,058) | |
| 44 | Totals | $ 30,751,385 | 100.00% | $ (1,800,201) | |
| 45 | RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (Line 30) (See RLM-8, Pages 1 & 2, Column (H)) | | | | $ (1,800,201) |

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Cost of Service
Schedule RLM-13


**OPERATING INCOME ADJUSTMENT NO. 8**
**OVERHEAD LINE MAINTENANCE**

| LINE NO. | ACCT NO. | DESCRIPTION | (A) COMPANY DATA RUCO D.R. 1.21 | (B) ADJUSTED CPI INFLATION | (C) RUCO ADJUSTMENT |
|---|---|---|---|---|---|
| 1 | 593 | 2002 Year-End Overhead Line Maintenance | $ 1,315,382 | $ 1,527,686 | |
| 2 | 593 | 2003 Year-End Overhead Line Maintenance | 1,286,976 | 1,461,389 | |
| 3 | 593 | 2004 Year-End Overhead Line Maintenance | 1,447,907 | 1,601,482 | |
| 4 | 593 | 2005 Year-End Overhead Line Maintenance | 1,822,616 | 1,949,873 | |
| 5 | 593 | 2006 Year-End Overhead Line Maintenance | 1,809,801 | 1,875,658 | |
| 6 | | Five Year Total (Sum Of Lines 1 Thru 5) | $ 7,682,682 | $ 8,416,087 | |
| 7 | | Average (Line 6 / 5Years) | | $ 1,683,217 | |
| 8 | 593 | Test-Year Ended Dec. 31, 2006 Overhead Line Maintenance (Per 1.21) | | $ 1,809,801 | |
| 9 | | Difference (Line 7 - Line 8) | | | $ (126,584) |
| 10 | | RUCO Adjustment (Line 8) (See RLM-8, Pages 1 & 2, Column (I)) | | | $ (126,584) |

**OPERATING INCOME ADJUSTMENT NO. 12**
**PAYROLL EXPENSE**

| LINE NO. | ACCT NO. | DESCRIPTION | (A) TEP AS FILED | (B) ALLOCATION FACTOR | (C) RUCO AS ADJUSTED |
|---|---|---|---|---|---|
| 1 | 500 | Steam Prod Oper-Supervision | $ 90,826 | 5.82% | $ 1,143 |
| 2 | 501 | Fuel - Steam | 9,757 | 0.62% | 123 |
| 3 | 502 | Steam Expenses | 108,250 | 6.93% | 1,362 |
| 4 | 505 | Electric Expenses | 37,134 | 2.38% | 467 |
| 5 | 506 | Steam Prod-Misc Expense | 28,275 | 1.81% | 356 |
| 6 | 510 | Maint-Supervision & Engr | 74,954 | 4.80% | 943 |
| 7 | 511 | Maint of Structures | 10,302 | 0.66% | 130 |
| 8 | 512 | Maint of Boiler Plant | 113,167 | 7.25% | 1,424 |
| 9 | 513 | Steam Prod-Mnt Elec Plnt | 22,539 | 1.44% | 284 |
| 10 | 514 | Steam Prod-Mnt Misc Plnt | 41,944 | 2.69% | 528 |
| 11 | 546 | Other Prod Oper-Supervision | 6,333 | 0.41% | 80 |
| 12 | 553 | Maint Gen & Elec Plant | 1,510 | 0.10% | 19 |
| 13 | 554 | Maint of Misc Oth Pwr Gen Plan | 549 | 0.04% | 7 |
| 14 | 556 | Sys Cntrol/Load Dispatch | 40,705 | 2.61% | 512 |
| 15 | 560 | Trans-Oper Supv & Engr | 16,860 | 1.08% | 212 |
| 16 | 561 | Trans-Load Dispatch | 6,433 | 0.41% | 81 |
| 17 | 561.2 | Load Dispatch - Monitor & Oper Trans | 14,200 | 0.91% | 179 |
| 18 | 561.3 | Load Dispatch - Trans Service & Sched | 1,849 | 0.12% | 23 |
| 19 | 561.5 | Reliability, Planning & Standards Dev | 6 | 0.00% | 0 |
| 20 | 561.7 | Generation Interconnection Studies | 94 | 0.01% | 1 |
| 21 | 562 | Trans-Station Expenses | 14 | 0.00% | 0 |
| 22 | 563 | Trans-Overhead Line Exp | 13 | 0.00% | 0 |
| 23 | 566 | Trans-Misc Oper Expense | 1,567 | 0.10% | 20 |
| 24 | 568 | Trans-Maint Supv & Engr | 5,300 | 0.34% | 67 |
| 25 | 569.1 | Maint of Computer HW | 1,331 | 0.09% | 17 |
| 26 | 569.2 | Maint of Computer SW | 6,674 | 0.43% | 84 |
| 27 | 570 | Trans-Maint Stn Equip | 35,510 | 2.27% | 447 |
| 28 | 571 | Trans-Maint of OH Lines | 5,008 | 0.32% | 63 |
| 29 | 573 | Trans-Maint Misc Trans Plnt | 2,096 | 0.13% | 26 |
| 30 | 580 | Dist-Oper Supv & Engr | 42,974 | 2.75% | 541 |
| 31 | 581 | Dist-Load Dispatching | 5,351 | 0.34% | 67 |
| 32 | 582 | Dist-Station Expenses | 1,931 | 0.12% | 24 |
| 33 | 583 | Dist-Overhead Line Exp | 13,504 | 0.86% | 170 |
| 34 | 584 | Dist-Underground Line Exp | 96 | 0.01% | 1 |
| 35 | 585 | Dist-Light/Signal Exp | 3 | 0.00% | 0 |
| 36 | 586 | Dist-Meter Expenses | 17,743 | 1.14% | 223 |
| 37 | 587 | Dist-Customer Install Exp | 4,893 | 0.31% | 62 |
| 38 | 588 | Dist-Misc Expense | 95,092 | 6.09% | 1,196 |
| 39 | 590 | Dist-Maint Supv & Engr | 14,091 | 0.90% | 177 |
| 40 | 592 | Dist-Maint Stn Equip | 18,751 | 1.20% | 236 |
| 41 | 593 | Dist-Maint of OH Lines | 21,713 | 1.39% | 273 |
| 42 | 594 | Dist-Maint of UG Lines | 752 | 0.05% | 9 |
| 43 | 595 | Dist-Mnt Line Transformers | 11,789 | 0.75% | 148 |
| 44 | 596 | Dist-Mnt Light/Signals | 17 | 0.00% | 0 |
| 45 | 597 | Dist-Maint of Meters | 2,464 | 0.16% | 31 |
| 46 | 598 | Dist-Maint Misc Plant | 3,017 | 0.19% | 38 |
| 47 | 903 | Cust Rec/Collection Exp | 181,637 | 11.63% | 2,285 |
| 48 | 908 | Customer Assistance Exp | 13,939 | 0.89% | 175 |
| 49 | 909 | Informational/Instrct Adv Exp | 1,716 | 0.11% | 22 |
| 50 | 920 | A&G Salaries | 377,238 | 24.16% | 4,747 |
| 51 | 925 | Injuries & Damages | 18,179 | 1.16% | 229 |
| 52 | 926 | Pensions & Benefits | 20,234 | 1.30% | 255 |
| 53 | 930.2 | General Advertising Exp | 9,138 | 0.59% | 115 |
| 54 | 935 | Maint General Plant | 2,273 | 0.15% | 29 |
| 55 | | | $ 1,561,735 | 100.00% | $ 19,651 |

NOTE: Calculation Of RUCO Test Year Payroll Expense Adjustment

| LINE NO. | DESCRIPTION | SOURCE | AMOUNT |
|---|---|---|---|
| 56 | Test Year O & M Payroll Expense | Company Workpapers | $ 52,712,850 |
| 57 | Average Wage Rate Increase As Of January 01, 2007 | Company Workpapers | 3.00% |
| 58 | Adjusted Test Year O & M Payroll Expense | Line 56 X Line 57 | $ 1,581,386 |
| 59 | Company Adjustment As Filed | TEP Sch. C-2, Pg 4 | $ 1,561,735 |
| 60 | Difference (See Column (C) For Account Allocation) | Line 58 - Line 59 | $ 19,651 |
| 61 | RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (M)) | | $ 19,651 |

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006



**OPERATING INCOME ADJUSTMENT NO. 13**
**PAYROLL TAX EXPENSE**

| LINE NO. | DESCRIPTION | REFERENCE | | (A) RUCO AS ADJUSTED |
|---|---|---|---|---|
| 1 | RUCO Adjusted Test Year O & M Payroll Expense | RLM-14, Col. (B), Line 58 | $ | 1,581,386 |
| 2 | Effective FICA Tax Rate For All TEP Wages | Company Workpapers | | 7.08% |
| 3 | Adjusted Test Year O & M Payroll Tax Expens( | Line 1 X Line 2 | $ | 111,962 |
| 4 | Adjustment Due To Increase In FICA Wage Base | Company Workpapers | $ | 30,415 |
| 5 | RUCO Total Adjustment To Test Year Payroll Tax Expens | Line 3 + Line 4 | $ | 142,377 |
| 6 | Company Adjustment As Filed | TEP Sch. C-2, Pg 4 | $ | 139,688 |
| 7 | Difference | Line 5 - Line 6 | $ | 2,689 |
| 8 | RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (N)) | Line 7 | $ | 2,689 |

Tucson Electric Power Company
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Cost of Service
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**OPERATING INCOME ADJUSTMENT NO. 17**
**CUSTOMER CARE AND BILLING NORMALIZATION**

| LINE NO. | ACCT NO. | | REFERENCE | (A) RUCO AS ADJUSTED |
|---|---|---|---|---|
| 1 | | Pre-Implementation Test Year Expenses (Jan., Feb. & Mar.) | Company Workpapers | $ 571,882 |
| 2 | | Pre-Implementation Monthly Expenses | Line 1 / 3 Months | 190,627 |
| 3 | | Pre-Implementation Annualized Expenses | Line 2 X 12 Months | $ 2,287,528 |
| 4 | 903 | Company Adjusted Test Year Expenses As Filed | Company Workpapers | $ 2,583,758 |
| 5 | 903 | Difference | Line 3 - Line 4 | $ (296,230) |
| 6 | 903 | RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (R)) | Line 5 | $ (296,230) |

Tucson Electric Power Company
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Cost of Service
Schedule RLM-17


**OPERATING INCOME ADJUSTMENT NO. 28**
**INCOME TAX EXPENSE**
(Thousands of Dollars)

| LINE NO. | DESCRIPTION | (A) REFERENCE | | (B) AMOUNT |
|---|---|---|---|---|
| | FEDERAL INCOME TAXES: | | | |
| 1 | Operating Income Before Taxes | Schedule RLM-7, Column (D), Line 13 + Line 11 | $ | 82,887 |
| | LESS: | | | |
| 2 | Arizona State Tax | Line 11 | | (3,549) |
| 3 | Interest Expense | Note (A) Line 22 | | (32,900) |
| 4 | Federal Taxable Income | Sum Of Lines 1, 2 & 3 | $ | 46,438 |
| 5 | Federal Tax Rate | Schedule RLM-1, Page 2, Column (A), Line 9 | | 35.00% |
| 6 | Federal Income Tax Expense | Line 4 X line 5 | $ | 16,253 |
| | STATE INCOME TAXES: | | | |
| 7 | Operating Income Before Taxes | Line 1 | $ | 82,887 |
| | LESS: | | | |
| 8 | Interest Expense | Note (A) Line 22 | | (32,900) |
| 9 | State Taxable Income | Line 7 + Line 8 | $ | 49,987 |
| 10 | State Tax Rate | Tax Rate | | 7.10% |
| 11 | State Income Tax Expense | Line 9 X Line 10 | $ | 3,549 |
| | TOTAL INCOME TAX EXPENSE: | | | |
| 12 | Federal Income Tax Expense | Line 6 | $ | 16,253 |
| 13 | State Income Tax Expense | Line 11 | | 3,549 |
| 14 | Total Income Tax Expense Per RUCO | Sum Of Lines 12 & 13 | $ | 19,802 |
| 15 | Total Income Tax Expense Per Company Filing (Schedule C-1) | | | (12,260) |
| 16 | Difference | Line 14 - Line 15 | $ | 32,063 |
| 17 | RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 7, Column (D), Line 11) | Line 16 | $ | 32,063 |

NOTE (A):
Interest Synchronization:

| LINE NO. | DESCRIPTION | | AMOUNT |
|---|---|---|---|
| 18 | Adjusted ACC Jurisdiction Rate Base (Schedule RLM-3, Column (D), Line 14) | $ | 936,123 |
| 19 | Weighted Cost Of Debt (Schedule RLM-18, Column (F), Line 1 + Line 2) | | 3.51% |
| 20 | Interest Expense (Line 18 X Line 19) | $ | 32,900 |

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

Cost of Service
Schedule RLM-18


**COST OF CAPITAL**

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) RUCO ADJUSTMENTS | (C) RUCO AS ADJUSTED | (D) PERCENT | (E) COST RATE | (F) WEIGHTED COST RATE |
|---|---|---|---|---|---|---|---|
| 1 | Short-term Debt | $ - | $ - | $ - | 0.00% | 0.00% | 0.00% |
| 2 | Long-term Debt | $ 805,636 | $ - | $ 805,636 | 55.00% | 6.39% | 3.51% |
| 3 | Preferred Stock | N/A | $ - | $ - | 0.00% | 0.00% | 0.00% |
| 4 | Common Equity | $ 659,157 | $ - | $ 659,157 | 45.00% | 9.44% | 4.25% |
| 5 | TOTAL CAPITAL | $ 1,464,793 | $ - | $ 1,464,793 | 100.00% | | |
| 6 | WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5) | | | | | | 7.76% |

References:
Column (A): Company Schedule D-1
Column (B): Testimony, WAR
Column (C): Column (A) + Column (B)
Column (D): Column (C), Line Item / Total Capital (Line 5)
Column (E): Testimony, WAR
Column (F): Column (D) X Column (E)

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

# DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 29, 2008

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## INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present the recommendations that result from my audit and review of Tucson Electric Power Company's ("TEP" or "Company") requested rate increase. TEP filed its rate application with the Arizona Corporation Commission ("ACC" or "Commission") on July 2, 2007. RUCO is recommending that rates in this docket be set based on the cost-of-service model, as set forth by the Company and as adjusted by RUCO. My testimony, as well as Rodney L. Moore's testimony, addresses the various adjustments RUCO recommends to the cost-of-service model. RUCO witness William A. Rigsby will address the cost of capital issues associated with the case.

The testimony of RUCO witness Ben Johnson addresses the two other models proposed by the Company and explains why they should be rejected. The testimony of Glen Gregory addresses RUCO's proposed rate design and cost of service analysis.

Q. Please describe your work effort on this project?

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application as it relates to operating income, rate base, and the Company's overall revenue requirements. This included the issuance of data requests, review of prior commission decisions, and discussions with Company personnel.

Q. Please identify the Exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-2.

Q. Please provide a summary of the issues you address in your direct testimony.

A. I address the following issues in my direct testimony:

RATE BASE

Accumulated Depreciation This adjustment restates the Company's recorded accumulated depreciation balance from 2004 through the end of the test year. The adjustment is necessary because during this time period the Company failed to use the Commission-authorized depreciation rates for accruing depreciation on its generation assets.

Springerville Unit I This adjustment restates the cost of the Springerville Unit I generating station from market to book.

Luna Plant This adjustment restates the cost of the Luna generating plant from market to book.

Implementation Regulatory Asset This adjustment decreases rate base to remove certain prior period expenses, which the Company has written off and for which the Commission never granted regulatory asset accounting authority.

OPERATING INCOME

Springerville Unit I Expenses This adjustment restates the cost of operating the Springerville Unit I plant from market cost to test year actual cost.

Luna Plant This adjustment restates the cost of operating the Luna plant from market cost to test year actual cost.

Implementation Regulatory Asset This adjustment removes the proposed amortization of financing costs that TEP has already written off and for which it does not have a deferral accounting order authorizing future recovery.

Bad Debt Expense This adjustment corrects an error the Company made in its calculation of the bad debt ratio.

Navajo Coal Prices This adjustment corrects an error the Company made in its calculation of the incremental cost increase per ton of Navajo coal.

Gain on Sale of $SO_2$ Allowances This adjustment credits the ratepayers with the revenue realized during the test-year from the sale of excess $SO_2$ credits from Springerville Unit 1 and 2.

Lime Usage Costs This adjustment removes the cost of extra lime usage during the test year at Springerville Unit I, as it is non-recurring.

Short-term Sales This adjustment credits ratepayers with 100% of the margins realized from short-term power sales.

Generating Facilities – Operating Lease This adjustment removes the capital lease cost associated with the Springerville Unit I Coal Handling capital lease and replaces it with a levelized lease cost in accordance with Decision No. 58497.

Miscellaneous Service Revenues This adjustment corrects an error the Company made in its calculation of the additional revenue that it will derive from the proposed increase in its Miscellaneous Service fees. Specifically, the error had the effect of understating the revenue related to late fee charges.

Wholesale Trading This adjustment includes the revenue and expenses associated with wholesale trading activities in test year operating income. RUCO recommends recovery of these wholesale margins through base rates as opposed to a PPFAC, as was recommended by the Company.

Rate Case Expense – Docket No. E-01933A-05-0650 This adjustment amortizes the test year cost of Docket No. E-01933A-05-0650 over four years.

Gain on Land Sales This adjustment reflects a 50/50 sharing of gains realized on the sales of land between ratepayers and shareholders.

OTHER ISSUES

Purchased Power and Fuel Adjustor Clause RUCO recommends rejection of the Company proposed Purchased Power and Fuel Adjustor Clause ("PPFAC"), and instead recommends a power supply adjustor that would be applicable solely to load that is incremental to that incurred in the test year.

Termination Cost Regulatory Asset – RUCO recommends rejection of the Company's proposed Termination Cost Regulatory Asset. No such asset exists and the notion of such an asset is illusory.

## RATE BASE

### Rate Base Adjustment #1 – Accumulated Depreciation

Q. Did RUCO perform a reconciliation of TEP's plant balances from the 2003 test year utilized in the 2004 Rate Check to the year end balances included in the test year ended December 31, 2006?

A. Yes. RUCO witness Rodney L. Moore performed this analysis and reconciliation.

Q. Were there any differences between the balances claimed by the Company in its application and RUCO's analysis?

A. Yes. As discussed in Mr. Moore's testimony, while RUCO was able to reconcile with the Company's plant-in-service balances, there was a large discrepancy between the accumulated depreciation balances computed by RUCO and the amounts recorded on the Company's books.

Q. Was RUCO able to ascertain the source of these large discrepancies?

A. Yes. While there were some differences in the Company's calculation methodology and RUCO's these accounted for a minor amount of the total discrepancy of $68 million. The majority of the discrepancy was attributable to the fact that in 2004 the Company began accruing depreciation on its generation assets at rates that were significantly lower than those that had been authorized by the Commission .

Q. Is the Company allowed to change its depreciation rates at its own discretion?

A. No. Under Arizona Administrative Code section R14-2-102(C)4, a Company cannot put new depreciation rates into effect until the Commission authorizes the changes.

Q. Did the Company offer any explanation for changing the depreciation rates on its generation assets without proper authorization from the Commission?

A. Yes. As was discussed at length in Docket No. E-01933A-05-0650, the Company continues to operate under the misconception that the ACC no longer has jurisdiction over its generation assets. While this may have become the case had the Commission not halted divestiture by its Track A Decision[1], the fact is divestiture *was* halted and the ACC continues to regulate and have jurisdiction of all of TEP's assets and operations. Accordingly, TEP must continue to adhere to the Commission rules and regulations, which includes the requirement for Commission authorization in order for TEP to change its depreciation rates.

Q. Besides failing to obtain Commission authorization to change its depreciation rates, are there any other reasons why such changes were inappropriate?

A. Yes. The depreciation rates on which TEP's current rates are based were significantly higher than those that TEP has been using to accrue depreciation expense since 2004. Thus, while ratepayers are paying the higher authorized depreciation expense through their current rates, the rate base is not being reduced by these payments because TEP is accruing accumulated depreciation at the lower, unauthorized, rates. This

[1] Decision No. 65154

is unfair because it results in ratepayers having to pay a return on plant that they have already paid for. Thus, it is necessary to increase the accumulated depreciation account by $49.504 million to ameliorate this inequity. This adjustment also has an impact of decreasing the Accumulated Deferred Income Tax balance by $19.554 million, for a net adjustment of $29.949 million.

**Rate Base Adjustment #2 – Springerville Unit I**

Q. Have you reviewed the Company's proposed ratemaking treatment for its Springerville Unit I generating plant?

A. Yes. The Company has made a proforma adjustment to remove the actual test year cost of Springerville Unit I, both capital and operating, and replace these actual costs with market price estimates. The overall affect of the adjustment is to increase the revenue requirement for the Springerville Unit I generating station.

Q. How does the Company justify using estimated market costs for rate setting purposes when the actual costs are not only lower, but are also known and measurable?

A. The Company relies on similar ratemaking treatment that was authorized in Decision No. 56659, dated October 1989 and again in Decision No. 57586 in 1991.

Q. Are the circumstances in the instant case the same as they were in 1989 and 1991 in regards to Springerville Unit I?

A. No. In those cases, the plant was owned by a third party which had recently purchased the plant from Alamito Company.[2] At that time TEP had a contract that required it to lease back the Springerville plant at $220 million in excess of its book value. When Decision No. 56659 was issued, TEP did not own the Springerville plant and was paying lease payments that incorporated the inflated cost of plant. The Commission's use of market based rates in that case had the effect of lowering the then-inflated lease payments to a price that was in line with similar arm's length transactions. In contrast, in the instant case TEP now owns a portion of the Springerville Unit 1 plant and the embedded cost of that plant is less than the market price estimations the Company has utilized in its currently proposed adjustment.

Q. Given the current circumstances of the Springerville plant, is a market price estimation adjustment appropriate?

A. No. It's clear that the Commission authorized the market price adjustment in Decision No. 56659 to recognize that the lease cost of the Unit 1 plant was not negotiated at arms-length and was significantly inflated. This is no longer the case and the plant's embedded costs are known and

[2] Pursuant to Decision No. 53815, TEP transferred its Springerville Unit No. 1 and San Juan Unit No. 3 to a newly formed subsidiary called Alamito Company. In 1984 the then-officers of TEP spun-off Alamito as an independent wholesale power company. Alamito was sold to a third party in 1986 at price that was $232 million in excess of the spin-off price.

measurable. The embedded costs do not appear to be inflated since they are lower than TEP's estimates of the prevailing market price. Thus, an adjustment from the embedded costs is neither appropriate nor warranted. Further, the notion that actual costs could be replaced with higher market estimated costs is contrary to even the most basic ratemaking principles. In this instance the Company continues to blindly adhere to a decades-old Commission decision that makes no sense under the current circumstances.

Q. What adjustment have you made?

A. As shown on Schedule RLM-4, Adjustment #2, I have reinstated the actual embedded cost of the Springerville Unit 1 plant in rate base. This adjustment also has impacts on TEP's test year operating income, which will be discussed later in that section of my testimony.

**Rate Base Adjustment #3 - Luna Plant**

Q. What ratemaking treatment is the Company requesting for its recently purchased Luna Plant?

A. TEP is requesting that this plant be excluded from rate base and that instead a market-based price for the output of this plant be included in operating expenses. The requested ratemaking treatment for the Luna Plant mirrors the ratemaking treatment requested for the Springerville Unit 1 plant, as just discussed.

Q. Does TEP own the Luna Plant?

A. Yes. TEP purchased this plant on November 12, 2004 and the plant entered service on April 4, 2006.

Q. Given that TEP owns this plant, why is the Company requesting that for ratemaking purposes it be treated as power purchased in the market?

A. According to a response to a RUCO data request, TEP believes that since it purchased this plant after its stranded cost settlement in Decision No. 62103 the plant is "deregulated" and the stockholders should be allowed to realize market-based profits from power sales from this plant to TEP's customers.

Q. Do you agree?

A. No. This flawed logic appears to have its roots in TEP's theory that Decision No. 62103 granted the Company market-indexed rates after 2008, which was the subject of Docket No. 01933A-05-0650. In that docket RUCO strongly disagreed with that position and provided substantial evidence and legal argument that TEP's market-indexed theory was incorrect. The Commission continues to have jurisdiction over TEP's operations, including generation. Accordingly market-indexed rates are inappropriate for a plant which the Company owns and uses to provide service to its captive customers. Instead, the Luna Plant should be priced at cost-of-service, as are all of TEP's other assets.

Q. What adjustment have you made?

A. As shown on Schedule RLM-, Adjustment #3, I have reinstated the actual embedded cost of the Luna plant in rate base. This adjustment also has impacts on TEP's test year operating income, which will be discussed later in that section of my testimony.

**Rate Base Adjustment #4 - Implementation Cost Regulatory Asset**

Q. Please discuss the Implementation Cost Regulatory Asset that TEP is proposing in rate base.

A. The Company is requesting a $47.5 million regulatory asset, referred to as the Implementation Cost Regulatory Asset ("ICRA"), to be included in rate base. Of this amount $14.2 million is related to certain expenses the Company incurred related to its efforts toward restructuring to retail access. Regulatory asset accounting was authorized for these costs pursuant to Decision No. 62103 ("the 1999 Settlement Agreement").

Q. Has TEP included any costs in its proposed regulatory asset for which Decision No. 62103 did not authorize regulatory asset accounting?

A. Yes. Under Generally Accepted Accounting Principles ("GAAP"), when TEP incurred certain debt financing costs and expenses related to amending and terminating certain coal contracts, the Company was required to write them off as expenses. TEP did not seek, nor was it granted, a deferral accounting order from the Commission that would allow the Company to capitalize these expenses as regulatory assets. Thus, these costs were expensed when incurred, in periods prior to the test year. Therefore, the Company has no asset related to these costs for which rate base recovery is warranted. Accordingly, my adjustment decreases rate base by $33.242 million to remove these prior-period expenses. There is also a companion adjustment discussed in the Operating Income section of my testimony related to amortization of these prior-period expenses.

Q. Has the Commission previously denied recovery of prior-period expenses for which a utility failed to obtain an accounting order?

A. Yes. In a recent UNS Gas rate case the Commission agreed with Staff and RUCO regarding the unrecoverability of prior-period expenses for which the utility never obtained regulatory asset accounting authority. In Decision No. 70011, dated November 27, 2007, the Commission stated:

> [T]he Company's failure to seek an accounting order from the Commission when the costs were incurred renders them unrecoverable as a regulatory asset.

**Rate Base Adjustment #5 – FAS 143 Accumulated Depreciation Write-off**

Q. Did TEP recently write-off a significant portion of its Accumulated Depreciation reserve?

A. Yes. The Financial Accounting Standards Board ("FASB") issued Statement No. 143, which modified the manner in which asset retirement obligations are to be accounted for under GAAP. The Statement requires companies to recognize the fair value of future retirement obligations (i.e. costs) at the point in time they are incurred as a liability. Prior to issuance of Statement No. 143, utilities accounted for retirement costs on a pro-rata basis over the life of the asset through their depreciation accruals. Accordingly, TEP's existing Accumulated Depreciation balance contained accruals for the retirement of assets. In order to comply with Statement No. 143, TEP, on January 1, 2003, wrote-off that portion of its Accumulated Depreciation balance that was related to retirement costs and transferred them to a liability account.

Q. Do you agree with TEP's method of accounting for Statement No. 143?

A. Yes. However, I do not agree the accounting required under Statement No. 143 for GAAP purposes is also appropriate for ratemaking purposes.

Q. Please explain.

A. While a change in accounting practice may be desirable from an accounting perspective, it may impact rates in a biased or unfair manner. Because the starting point from which the regulatory body determines a utility's rates is its GAAP-compliant financial statements, any change in GAAP accounting practice must be carefully analyzed and its impact on the resultant rates fully understood before a determination can be made if such accounting change is appropriate for ratemaking treatment.

Q. Have you done such an analysis?

A. Yes. As just discussed, utilities have historically recognized the cost of asset retirement through annual depreciation accruals. These retirement costs, prior to Statement No. 143, resided in TEP's Accumulated Depreciation account, which under the ratemaking formula serves to reduce rate base. The account serves as a rate base reduction because it represents the portion of TEP's plant investment that it has already recovered through its depreciation accruals. Depreciation accruals (expenses) are included in the ratemaking formula, thus, by definition the Accumulated Depreciation account is comprised of amounts paid for by ratepayers. As just mentioned this account reduces rate base, thereby ensuring that ratepayers do not continue to pay a return on that portion of TEP's rate base investment for which ratepayers have already provided reimbursement. Statement No. 143, however, has upset the equity of depreciation accounting because it requires TEP to write-off a portion of the accumulated depreciation balance that ratepayers have already paid for. This write-off decreases the Accumulated Depreciation balance, which in turn increases rate base. The overall result of this accounting is that ratepayers will have to pay a return on portions of the Company's plant investment that ratepayers have already paid for through their utility rates. Thus, while Statement No. 143 may be appropriate from a financial accounting standpoint it has unintended consequences on regulated companies, and if recognized for ratemaking purposes will result in double recovery of the previously accrued asset retirement costs.

Q. What adjustment have you made?

A. I have reversed TEP's $112.8 million write-off of its Accumulated Depreciation balance. My adjustment is necessary to prevent ratepayers from having to pay again for assets that they have already paid for.

**OPERATING INCOME**

**Operating Adjustment #1 - Springerville Unit 1 Operating Expenses**

Q. What adjustment are you recommending for the Springerville Unit 1 expenses?

A. As previously discussed in the Rate Base section of my testimony, the Company has proposed an adjustment that would replace the actual test year embedded costs of the Springerville Unit 1 plant with market-indexed estimated costs. I have recommended that the Company's adjustment be rejected and instead the actual test year embedded costs be reflected for ratemaking purposes. Operating Adjustment #1 simply reflects the operating income impacts of recognizing the actual test year expenses associated with Unit 1 as opposed to the Company's proposed market estimated costs. As shown on Schedule RLM-8, Operating Adjustment #1, this decreases operating expenses by $32.7 million.

**Operating Adjustment #10 - Luna Plant Expenses**

Q. What adjustment are you recommending for the Luna plant expenses?

A. As previously discussed in the Rate Base section of my testimony, the Company has proposed an adjustment that would replace the actual test year embedded costs of the Luna plant with market-indexed estimated costs. I have recommended that the Company's adjustment be rejected and instead the actual test year embedded costs be reflected for ratemaking purposes. Operating Adjustment #10 simply reflects the operating income impacts of recognizing the actual test year expenses associated with the Luna plant as opposed to the Company's proposed market-index estimated costs. As shown on Schedule RLM-8, Operating Adjustment #10, this decreases operating expenses by $15.96 million.

**Operating Adjustment #11 – Implementation Cost Regulatory Asset**

Q. Please discuss your adjustment to remove the amortization expense associated with prior-period expenses.

A. As was discussed previously in the rate base section of my testimony, the Company is proposing regulatory asset accounting for certain expenses it incurred in prior periods for which it never obtained authorization from the Commission. I have removed these prior-period expenses from rate base and likewise have decreased operating expenses by $8.311 million to remove the proposed amortization of these prior-period expenses.

**Operating Adjustment #15 – Bad Debt Expense**

Q. Are you making an adjustment to the Company's proposed bad debt expense?

A. Yes. Pursuant to a data request, the Company acknowledged that it had incorrectly computed the bad debt ratio and provided a revised ratio. My adjustment restates bad debt expense based on the Company's correction to its bad debt ratio. As shown on Schedule MDC-1, this adjustment reduces bad debt expense by $520,078.

**Operating Adjustment #16 – Navajo Coal Prices**

Q. Has the Company proposed an adjustment for an increased cost of Navajo coal?

A. Yes. The Company made a calculation where it compared its test year Navajo coal costs per ton with a forecasted 2007 cost of coal per ton and determined a $4.85 cost increase per ton. TEP then multiplied the cost increase by the number of tons used in the test year to derive a total cost increase of $2.780 million.

Q. Do you agree with this calculation?

A. No. The Company's calculation understates the actual test year cost of coal per ton and overstates the 2007 forecast. As a result, the incremental cost of $4.85 per ton is erroneous. Using the actual cost per ton in the test year of $30.23 and the actual 2007 cost per ton of $31.28

the incremental increase is only $1.05 not $4.85 as calculated by the Company. When multiplied by the number of tons burned in the test year the corrected calculation indicates a $585,765 increase in Navajo coal costs as opposed to the $2.780 million calculated by the Company. My corrected calculations are shown on Schedule MDC-2 and result in a $2.194 million decrease in operating expenses.

**Operating Adjustment #18 – Gain on Sale of $SO_2$ Allowances**

Q. During the test year did the Company generate any revenue pursuant to sales of its $SO_2$ allowances?

A. Yes. During the test year TEP realized $6.716 million in revenues from the sale of $SO_2$ allowances. The Company has made a proforma adjustment in this case to remove this test year revenue from its operating income.

Q. Do you agree with this treatment?

A. No. As was explained in the response to RUCO data request 5.10, the revenue that was realized from the sale of excess $SO_2$ credits was generated as a result of improved equipment and operation at Springerville Units 1 and 2. Since ratepayers bear the cost of these plants they should also realize any benefits received from these plants. As shown on Schedule RLM-8, I have increased revenues by $6.716 million to credit ratepayers with the test year revenues realized from the sales of $SO_2$ allowances.

**Operating Adjustment #21 - Lime Usage Costs**

Q. Please discuss the Company's proposed adjustment for extra lime usage costs.

A. During the test year TEP performed additional scrubbing of Springerville Units 1 and 2 by using more lime than normal to reduce emissions so that Unit III could operate. Since these costs are abnormal and non-recurring the Company removed these costs for Springerville Unit II.

Q. Why didn't TEP also remove the extra lime usage costs for Unit I?

A. Since the Company removed all of the Unit I operating costs from the test year and replaced those actual costs with market costs, the extra lime usage was also removed as part of that adjustment. As discussed earlier in my testimony, I have reversed that adjustment to include the actual test year cost of operating Springerville Unit I. As result of this earlier adjustment it is now necessary to remove the non-recurring lime costs from the test year Springerville Unit I expenses. This adjustment reduces test year Springerville Unit I expenses by a net amount of $295,482.

**Operating Adjustment #22 - Short-term Sales**

Q. What ratemaking treatment is the Company proposing for its short-term sales revenues and expenses?

A. The Company has removed the test year revenues and expenses generated through short-term sales. TEP proposes that 90% of the net margin associated with short-term power sales be credited to ratepayers via the proposed PPFAC.

Q. Do you agree with the Company's proposed treatment of the revenues and expenses associated with short-term sales?

A. No. As was discussed previously in my testimony, RUCO is recommending that TEP's proposed PPFAC be rejected. Thus, the margins realized from these sales need to be credited to ratepayers through base rates. Further, RUCO does not agree that TEP shareholders should be allowed to retain 10% of these margins. Ratepayers pay all the costs associated with generation of the power that is sold through short-term sales and should, therefore, should be credited with 100% of the margins realized from those sales.

…

**Operating Adjustment #23 – Generating Facilities – Operating Lease**

Q. Please explain the Company's proposed adjustment related to the Sundt and Springerville Common Facilities and the Springerville Coal Handling Facilities.

A. For ratemaking purposes, pursuant to Decision No. 58497, the Company accounts for these facilities as levelized lease payments, whereas for book purposes these facilities are accounted for as capital leases. The Company adjustment converts the recorded capital lease accounting to the ratemaking levelized lease expense accounting. The net result is a decrease in operating expenses of approximately $21 million.

Q. Do agree with this adjustment?

A. Yes. Decision No. 58497 does require this adjustment. However, I do not agree with the portion of the adjustment that pertains to the Springerville Coal Handling facilities.

Q. Please explain.

A. As discussed earlier the Company has treated the Springerville Unit I on a market-based rate, therefore removing the test year actual expenses associated with that plant. Because the Company has already removed the expenses associated with 50% of the Springerville Coal Handling facility as part of that adjustment, TEP argues that it is unnecessary in this adjustment.

Q. Do you agree?

A. Yes, that would the case if one where to accept the Company's adjustment to treat Springerville Unit I at market rates. RUCO, however, has rejected this treatment and reinstated the actual test year Springerville Unit I expense. Thus, it is necessary to now remove 100% of the Unit I and II Coal Handling expense as part of the leased facilities adjustment required by Decision No. 58497. This adjustment decreases operating expenses by $9.407 million to restate the capital lease expense of 100% of the Springerville Coal Handling facilities to the required levelized lease expense for these facilities.

**Operating Adjustment #24 – Miscellaneous Service Revenue**

Q. Has the Company proposed any changes in its Miscellaneous Service Fees?

A. Yes. The Company is proposing to increase the tariffs for some of its Miscellaneous Service Fees[3] to more closely match the current cost of providing these services. The Company then calculated a pro forma adjustment to reflect the additional revenues that will be generated by these increased service fees.

. . .

[3] Service Connect and Reconnect Fees, Meter Reread, Meter Testing, and Late Fees.

Q. Do you agree with the Company's quantification of the additional revenue that will be generated as a result of these increased fees?

A. The Company in its supplemental response to data request RUCO 3.14 acknowledged that it made an error in its calculation of the additional revenue that will be generated by its proposed late fee tariff (see Attachment MDC-A). An adjustment to increase proforma Miscellaneous Service Fee by $1.161 million is necessary to correct this error.

**Operating Adjustment #25 – Wholesale Trading**

Q. Has the Company proposed an adjustment to its wholesale trading revenues and expenses?

A. Yes. The Company is proposing to remove the revenues and expenses associated with TEP's wholesale trading activity from test year operating income.

Q. What is TEP's rationale for this adjustment?

A. TEP claims that the margins that are realized through the Company's wholesale trading activities should be credited to TEP's proposed PPFAC.

Q. Does the Company therefore recognize that these margins should be credited to ratepayers?

A. Yes. The administrative costs of these activities (i.e. payroll, office expenses, etc.) remain embedded in test year expenses. Thus, since ratepayers are bearing the cost of these activities they should be credited with the margins realized from wholesale trading. The Company is not arguing this point, but rather agues that these credits should flow back to the ratepayer through the PPFAC.

Q. Do you agree?

A. Yes, I agree that these margins should be credited to ratepayers. However, since RUCO is not recommending approval of the company-proposed PPFAC I have made an adjustment to include these wholesale revenues and expenses on the test year income statement, for recovery through base rates. This adjustment increases test year operating income by $1.7 million.

**Operating Adjustment #26 – Rate Case Expense – Docket No. E-01933A-05-0650**

Q. Does TEP's test year expenses include any costs related to its Motion to Amend Decision No. 62103?

A. Yes. TEP's test year operating expenses include $481,447 in expenditures related to its Motion to Amend.

Q. For ratemaking purposes is this a recurring cost?

A. No. The expenditures in Docket No. E-01933A-05-0650 relate to a unique rate litigation, and accordingly should be amortized. I am recommending a four year amortization, which reduces test year expenses by $361,085.

**Operating Adjustment #27 – Gain on Land Sales**

Q. Has TEP realized gains on sales of its land holdings over past several years?

A. Yes. TEP has realized over $2 million in gains on the sale of land over the past several years.

Q. Should ratepayers be credited with a portion of these gains?

A. Yes. The Commission has typically supported the 50/50 sharing of gains on sales of utility property between ratepayers and shareholders. My adjustment therefore credits ratepayers with approximately $1 million in gains, and amortizes this amount over four years, for an expense reduction of approximately $250,000 per year.

## OTHER ISSUES

**Purchased Power and Fuel Adjustment Clause**

Q. Is TEP proposing a Purchased Power and Fuel Adjustment Clause in this case?

A. Yes. Currently the Company does not have a Purchased Power and Fuel Adjustment Clause ("PPFAC") and claims that such an adjustor is warranted because TEP "relies on natural gas and purchased power to meet a growing percentage of its customer demand"[4]. TEP's proposed

[4] Direct Testimony of David G. Hutchens at page 30, lines 20-21.

adjustor is patterned after the power supply adjustor authorized for APS in Decision No. 69663.

Q. What criteria must a utility meet to warrant the authorization of an automatic adjustor mechanism?

A. The Arizona Court of Appeals addressed the eligibility requirements of automatic adjustment mechanisms in Scates v. Arizona Corporation Commission. The court indicated that such mechanisms are restricted to certain narrowly defined operating expenses that are characterized by fluctuations. The Arizona Corporation Commission also defined automatic adjustor mechanisms as applying to expenses that routinely, or widely, fluctuate. The ACC stated the following regarding automatic adjustor mechanisms:

> The principal justification for a fuel adjustor is volatility in fuel prices. A fuel adjustor allows the Commission to approve changes in rates for a utility in response to volatile changes in fuel or purchased power prices without having to conduct a rate case. (Arizona Public Service Company, Decision No. 56450, at page 6, dated April 13, 1989)

Q. Do you believe that the characteristics of TEP's fuel and purchased power mix meet this criteria?

A. No. The primary source of TEP's power sales is from its coal fired plants[5]. Historically, prices of delivered coal have not been volatile or widely fluctuating, as would be required by Scates for automatic adjustment. As

[5] During the test year TEP generated 81% of its sales from its coal fired plants.

shown in the response to data request RUCO 8.5 (see Attachment MDC-B), the delivered price of coal has increased by approximately 8% over the past three years. This is less than inflation for the same period, and thus, hardly qualifies as a volatile expense that justifies extraordinary ratemaking treatment. Further, TEP has made proforma adjustments to its test year delivered coal prices to reflect the increases it anticipates post-test year. Given these adjustments, and the lack of any demonstrated volatility in coal prices, a mechanism for automatic adjustment simply isn't warranted.

Q. What are the characteristics of TEP's other sources of power?

A. During the test year, TEP supplied 6.3% of its power sales via gas generation and 12.6% with market purchases. Both of these sources have historically been somewhat less stable than coal prices, however, again, these sources are relied on for less than 20% of TEP's power sales.

Q. Given the overall characteristics of TEP's power sources does RUCO recommend approval of the Company's proposed PPFAC?

A. No. The proposed PPFAC would allow TEP to automatically flow through the cost of its power to ratepayers outside of a traditional rate case where otherwise all ratemaking elements would be analyzed and rates set on a comprehensive examination of the Company's financial status. Instead fuel and purchased power would be afforded single ratemaking issue status under TEP's proposed PPFAC. In effect, under this proposal TEP would be held harmless not only from cost increases in fuel and purchased power, but also be held harmless from management and operation of its own generation resources, which comprise over 80% of its power sales.

Q. Without the proposed PPFAC will TEP be required to bear an unacceptable level of risk?

A. No. Based on the Company's test year sources of power, I do not believe TEP is subject to an unacceptable level of risk that would not be adequately compensated through its return on equity. However, RUCO is aware that the percentage of power that TEP supplies through market purchases has continued to grow each year (see Attachment MDC-B). While coal continues to generate approximately the same number of MWh sales each year, purchases continue to increase, thus annually becoming a greater percentage of sales. This trend indicates that TEP is relying primarily on purchases to serve any load growth. Since TEP has not indicated any plans for the purchase of new plants, it appears that purchases will continue to supply TEP's growth into the near term future.

...

Q. Could this pose potential higher levels of risk in the future for TEP?

A. Yes. Potentially the risk of volatility in the market will rise, as long as TEP has annual load growth and continues to rely on the market to serve this growth.

Q. How does RUCO propose to protect TEP from its growing reliance on sources of power that have less price stability than its coal resources?

A. Again, because of the relative price stability of the majority of TEP's power, and the proforma adjustments the Company has made to increase the test year prices of delivered coal to projected 2009 price levels, TEP's current risk exposure is limited to future load growth that will be subject to market purchases. Thus, RUCO is proposing a power supply adjustor that would be applicable only to incremental load above the test year level. RUCO's proposed power supply adjustor would protect TEP from market price volatility related to load growth, while at the same time will not shift the operational risk of TEP's own generating facilities to ratepayers.

Q. How would RUCO's proposed power supply adjustor work?

A. The power supply adjustor would be initially set at zero, and would not be eligible for resetting until December 2010. In December 2010 TEP would compare its actual purchased power expenses with the amount embedded in base rates in this case and multiply the incremental difference (whether negative or positive) by the increase in retail MWh sales from the 2006 test year until the 2009 calendar year. The product of this calculation would be divided by the total 2009 retail MWh sales to yield the annual amount of the power supply adjustor per kWh for the ensuing year.

Q. Does RUCO's proposal include a forward looking component to the power supply adjustor?

A. No. RUCO does not believe the characteristics of TEP's fuel and purchased power supplies warrant the use of estimations or projections of purchased power costs. Such a methodology would only serve to complicate TEP's rate structure and require further adjustment when actual prices became known.

Q. Didn't the Company itself propose a similar adjustor mechanism in Docket E-01933A-05-0650?

A. Yes. Witness James Pignatelli proposed an Energy Cost Adjustment Clause ("ECAC") mechanism in the testimony he filed in Docket No. E-1933A-05-0650. The proposed ECAC was very similar to the mechanism that RUCO is recommending in this docket. The Company proposed ECAC also would have been applicable only to that portion of TEP's load that was incremental to the test year level. In support of the ECAC Mr. Pignatelli observed the following:

> The proposed ECAC is an adjustment clause that allows the portion of retail load above the cost-of-service test year sales to be recovered at market-based prices. It differs from some other purchase power and fuel clauses in that it does not shift any

> operational risk of TEP's generating facilities to the Company's customers and does not include and fuel cost risks associated with the Test Year Retail Sales portion of the load.
>
> and
>
> Although TEP serves the majority of its load with company-owned generating resources, it relies on purchased power to meet a growing percentage of its customer demand. Because this power is purchased at market prices, TEP should be allowed to recover market prices for a portion of its load.[6]

Thus, the Company also recognized the merits of the type of power adjustor that RUCO is now also recommending.

**Termination Cost Recovery Asset**

Q. What is the Termination Cost Recovery Asset?

A. The Company claims that the Termination Cost Recovery Asset ("TCRA") is a regulatory asset "that represents the economic harm that will have been suffered by TEP if the 1999 Settlement Agreement is not honored and generation service rates are based solely on cost-of-service principles."[7]

...

[6] Direct testimony of James Pignatelli, Docket No. E-0133A-05-0650, pages 20, 21

[7] Testimony of James Pignatelli, Docket No. E-01933A-07-0402, page 20, lines 3-5.

Q. Has the Commission issued an accounting order or a prior decision establishing this "regulatory asset"?

A. No. This "regulatory asset" is merely something that the Company has invented in this docket and has not in any way previously been afforded regulatory asset status by this Commission.

Q. What is your understanding of TEP's logic in inventing the TCRA?

A. TEP appears to believe that the Company was somehow guaranteed market generation rates in 2009 pursuant to the 1999 Settlement Agreement, and that if, as a result of this docket TEP is permitted to charge those market rates, the Company should be compensated for the rate decreases and rate freeze that were part of that Settlement Agreement. This issue was thoroughly vetted in the hearing in Docket No. E-01933A-05-0650, and none of the parties to that docket, other than TEP, agreed with this interpretation of the 1999 Settlement Agreement. No Commission decision was rendered on this issue in Docket No. E-01933A-05-0650, but the matter was consolidated with the instant docket. RUCO's position on this issue has not changed since that hearing, and RUCO refers the reader to the testimonies filed in that docket for a full record of the parties' positions. Further, the rate decreases that TEP implemented in 1999 and 2000 were merely reaffirmed in the 1999

Settlement Agreement and had actually been previously authorized by the Commission in Decision No. 61104, dated August 28, 1998[8].

Q. Setting aside the disagreement on whether the 1999 Settlement Agreement granted TEP market rates in 2009, do you agree with the Company's quantification of this so called "regulatory asset"?

A. No. The Company claims that this so called "regulatory asset" has a value of $788 million as of May 2008 which will increase to $921 million by December 2006? This amount is based on the $111 million annual revenue deficiency that the Company claimed in its 2004 Rate Check, accumulated through 2008, plus interest and return.

Q. Did the Commission issue a decision on the 2004 Rate Check and make a finding of fair value and a revenue deficiency amount?

A. No. The terms of the Settlement Agreement provided that the Rate Check was to be filed in June 2004 to ensure that TEP was not overearning as a result of the stranded cost recovery estimates in the Settlement Agreement. According to Decision No. 62103 the 2004 Rate Check could only result in a rate decrease, not a rate increase. None of the parties to the 2004 Rate Check found that TEP was overearning, thus the question of a rate decrease was moot. Because any rate increase was precluded under the 1999 Settlement Agreement, no hearings were held and there

[8] Decision No. 61104 authorized a settlement agreement between TEP, Staff, RUCO, and other intervenors in TEP's Application for Implementation of a Shared-Savings Proposal.

was no Commission finding of fair value or any specific revenue deficiency.

Q. So the $111 million revenue deficiency that forms the basis of TEP's proposed TCRA is not a finding of the Commission?

A. No. The $111 million is merely the amount of deficiency that TEP represented in its filing, which was comprised of a large number of proforma adjustments, with which the parties in large part disagreed. RUCO represented the deficiency was approximately $30 million; Staff calculated a revenue deficiency of approximately $66 million. The Commission never established a revenue deficiency in any amount since it issued no decision in the 2004 Rate Check, thus, there is no basis of TEP's claim of an annual $111 million "harm" it has born since the Rate Check.

Q. So RUCO disagrees with TEP regarding the existence and justification of a "regulatory asset" as well as to the amount of the so-called "regulatory asset"?

A. Yes. RUCO recommends the Company proposed TCRA be rejected for the above discussed reasons as well as those set forth in RUCO's testimony and briefs filed in Docket No. E-01933A-05-0650.

**True-up Revenues**

Q. What does TEP mean by the term "true-up revenues"?

A. In the 1999 Settlement Agreement, TEP was permitted to collect a portion of its stranded costs through a fixed Competitive Transition Charge ("CTC"). The Settlement Agreement provided that TEP would collect the fixed CTC of 0.93 cents/kWh (average), until it had collected $450 million, or through the end of 2008, which ever occurred first. At that time, the fixed CTC would terminate. In 2007, TEP projected that it would meet the $450 million target in early 2008. However, in Decision No. 69568, the Commission permitted TEP to continue collecting the fixed CTC until further order of the Commission, and instructed that the amount of fixed CTC that TEP collects above the $450 million target would be considered "True Up Revenue" and would be subject to refund, credit or another mechanism to protect customers.

Q. Has TEP proposed a method of refunding or crediting customers with the true-up revenue?

A. Yes. TEP proposes a slightly lower TCRA than it otherwise believes it is entitled to in recognition of the true-up revenue.

...

Q. Does RUCO believe that is an appropriate method to compensate customers for their overpayment of the Fixed CTC?

A. No. As discussed above, RUCO does not believe TEP is entitled to a TCRA in any amount. Therefore, RUCO proposes that the true-up revenue be credited back to customers through a different mechanism.

Q. What is RUCO's recommended mechanism to refund the over collection?

A. RUCO recommends that customers receive bill credits, based on their individual usage during the over collection period. Until the magnitude of the over collections is actually known, an appropriate refunding period cannot be determined.

Q. Does this conclude your direct testimony?

A. Yes.

## APPENDIX I

Qualifications of Marylee Diaz Cortez

**EDUCATION:** University of Michigan, Dearborn
B.S.A., Accounting 1989

**CERTIFICATION:** Certified Public Accountant - Michigan
Certified Public Accountant – Arizona

**EXPERIENCE:** Audit Manager
Residential Utility Consumer Office
Phoenix, Arizona 85007
July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States.

Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION

| Utility Company | Docket No. | Client |
|---|---|---|
| Potomac Electric Power Co. | Formal Case No. 889 | Peoples Counsel of District of Columbia |
| Puget Sound Power & Light Co. | Cause No. U-89-2688-T | U.S. Department of Defense - Navy |
| Northwestern Bell-Minnesota | P-421/EI-89-860 | Minnesota Department of Public Service |
| Florida Power & Light Co. | 890319-EI | Florida Office of Public Counsel |
| Gulf Power Company | 890324-EI | Florida Office of Public Counsel |
| Consumers Power Company | Case No. U-9372 | Michigan Coalition Against Unfair Utility Practices |
| Equitable Gas Company | R-911966 | Pennsylvania Public Utilities Commission |
| Gulf Power Company | 891345-EI | Florida Office of Public Counsel |

| Utility Company | Docket No. | Client |
|---|---|---|
| Jersey Central Power & Light | ER881109RJ | New Jersey Department of Public Advocate Division of Rate Counsel |
| Green Mountain Power Corp. | 5428 | Vermont Department of Public Service |
| Systems Energy Resources | ER89-678-000 & EL90-16-000 | Mississippi Public Service Commission |
| El Paso Electric Company | 9165 | City of El Paso |
| Long Island Lighting Co. | 90-E-1185 | New York Consumer Protection Board |
| Pennsylvania Gas & Water Co. | R-911966 | Pennsylvania Office of Consumer Advocate |
| Southern States Utilities | 900329-WS | Florida Office of Public Counsel |
| Central Vermont Public Service Co. | 5491 | Vermont Department of Public Service |
| Detroit Edison Company | Case No. U-9499 | City of Novi |
| Systems Energy Resources | FA-89-28-000 | Mississippi Public Service Commission |
| Green Mountain Power Corp. | 5532 | Vermont Department of Public Service |

| Utility Company | Docket No. | Client |
|---|---|---|
| United Cities Gas Company | 176-717-U | Kansas Corporation Commission |
| General Development Utilities | 911030-WS & 911067-WS | Florida Office of Public Counsel |
| Hawaiian Electric Company | 6998 | U.S. Department of Defense - Navy |
| Indiana Gas Company | Cause No. 39353 | Indiana Office of Consumer Counselor |
| Pennsylvania American Water Co. | R-00922428 | Pennsylvania Office of Consumer Advocate |
| Wheeling Power Co. | Case No. 90-243-E-42T | West Virginia Public Service Commission Consumer Advocate Division |
| Jersey Central Power & Light Co. | EM89110888 | New Jersey Department of Public Advocate Division of Rate Counsel |
| Golden Shores Water Co. | U-1815-92-200 | Residential Utility Consumer Office |
| Consolidated Water Utilities | E-1009-92-135 | Residential Utility Consumer Office |
| Sulphur Springs Valley Electric Cooperative | U-1575-92-220 | Residential Utility Consumer Office |
| North Mohave Valley Corporation | U-2259-92-318 | Residential Utility Consumer Office |

| Utility Company | Docket No. | Client |
|---|---|---|
| Graham County Electric Cooperative | U-1749-92-298 | Residential Utility Consumer Office |
| Graham County Utilities | U-2527-92-303 | Residential Utility Consumer Office |
| Consolidated Water Utilities | E-1009-93-110 | Residential Utility Consumer Office |
| Litchfield Park Service Co. | U-1427-93-156 & U-1428-93-156 | Residential Utility Consumer Office |
| Pima Utility Company | U-2199-93-221 & U-2199-93-222 | Residential Utility Consumer Office |
| Arizona Public Service Co. | U-1345-94-306 | Residential Utility Consumer Office |
| Paradise Valley Water | U-1303-94-182 | Residential Utility Consumer Office |
| Paradise Valley Water | U-1303-94-310 & U-1303-94-401 | Residential Utility Consumer Office |
| Pima Utility Company | U-2199-94-439 | Residential Utility Consumer Office |
| SaddleBrooke Development Co. | U-2492-94-448 | Residential Utility Consumer Office |
| Boulders Carefree Sewer Corp. | U-2361-95-007 | Residential Utility Consumer Office |
| Rio Rico Utilities | U-2676-95-262 | Residential Utility Consumer Office |
| Rancho Vistoso Water | U-2342-95-334 | Residential Utility Consumer Office |
| Arizona Public Service Co. | U-1345-95-491 | Residential Utility Consumer Office |
| Citizens Utilities Co. | E-1032-95-473 | Residential Utility Consumer Office |

| Utility Company | Docket No. | Client |
|---|---|---|
| Citizens Utilities Co. | E-1032-95-417 et al. | Residential Utility Consumer Office |
| Paradise Valley Water | U-1303-96-283 & U-1303-95-493 | Residential Utility Consumer Office |
| Far West Water | U-2073-96-531 | Residential Utility Consumer Office |
| Southwest Gas Corporation | U-1551-96-596 | Residential Utility Consumer Office |
| Arizona Telephone Company | T-2063A-97-329 | Residential Utility Consumer Office |
| Far West Water Rehearing | W-0273A-96-0531 | Residential Utility Consumer Office |
| SaddleBrooke Utility Company | W-02849A-97-0383 | Residential Utility Consumer Office |
| Vail Water Company | W-01651A-97-0539 & W-01651B-97-0676 | Residential Utility Consumer Office |
| Black Mountain Gas Company & Northern States Power Company | G-01970A-98-0017 & G-03493A-98-0017 | Residential Utility Consumer Office |
| Paradise Valley Water Company & Mummy Mountain Water Company | W-01303A-98-0678 & W-01342A-98-0678 | Residential Utility Consumer Office |
| Bermuda Water Company | W-01812A-98-0390 | Residential Utility Consumer Office |
| Bella Vista Water Company & Nicksville Water Company | W-02465A-98-0458 & W-01602A-98-0458 | Residential Utility Consumer Office |
| Paradise Valley Water Company | W-01303A-98-0507 | Residential Utility Consumer Office |
| Pima Utility Company | SW-02199A-98-0578 | Residential Utility Consumer Office |
| Far West Water & Sewer Company | WS-03478A-99-0144 Interim Rates | Residential Utility Consumer Office |

| Utility Company | Docket No. | Client |
|---|---|---|
| Vail Water Company | W-01651B-99-0355<br>Interim Rates | Residential Utility<br>Consumer Office |
| Far West Water & Sewer Company | WS-03478A-99-0144 | Residential Utility<br>Consumer Office |
| Sun City Water and Sun City West | W-01656A-98-0577 &<br>SW-02334A-98-0577 | Residential Utility<br>Consumer Office |
| Southwest Gas Corporation &<br>ONEOK, Inc. | G-01551A-99-0112 &<br>G-03713A-99-0112 | Residential Utility<br>Consumer Office |
| Table Top Telephone | T-02724A-99-0595 | Residential Utility<br>Consumer Office |
| U S West Communications &<br>Citizens Utilities Company | T-01051B-99-0737 &<br>T-01954B-99-0737 | Residential Utility<br>Consumer Office |
| Citizens Utilities Company | E-01032C-98-0474 | Residential Utility<br>Consumer Office |
| Southwest Gas Corporation | G-01551A-00-0309 &<br>G-01551A-00-0127 | Residential Utility<br>Consumer Office |
| Southwestern Telephone Company | T-01072B-00-0379 | Residential Utility<br>Consumer Office |
| Arizona Water Company | W-01445A-00-0962 | Residential Utility<br>Consumer Office |
| Litchfield Park Service Company | W-01427A-01-0487 &<br>SW-01428A-01-0487 | Residential Utility<br>Consumer Office |
| Bella Vista Water Co., Inc. | W-02465A-01-0776 | Residential Utility<br>Consumer Office |
| Generic Proceedings Concerning<br>Electric Restructuring Issues | E-00000A-02-0051 | Residential Utility<br>Consumer Office |
| Arizona Public Service Company | E-01345A-02-0707 | Residential Utility<br>Consumer Office |
| Qwest Corporation | RT-00000F-02-0271 | Residential Utility<br>Consumer Office |

| Utility Company | Docket No. | Client |
|---|---|---|
| Arizona Public Service Company | E-01345A-02-0403 | Residential Utility Consumer Office |
| Citizens/UniSource | G-01032A-02-0598<br>E-01032C-00-0751<br>E-01933A-02-0914<br>E-01302C-02-0914<br>G-01302C-02-0914 | Residential Utility Consumer Office |
| Arizona-American Water Company | WS-01303A-02-0867 | Residential Utility Consumer Office |
| Arizona Public Service Company | E-01345A-03-0437 | Residential Utility Consumer Office |
| UniSource | E-04230A-03-0933 | Residential Utility Consumer Office |
| Arizona Public Service Company | E-01345A-04-0407 | Residential Utility Consumer Office |
| Qwest Corporation | T-01051B-03-0454 &<br>T-00000D-00-0672 | Residential Utility Consumer Office |
| Tucson Electric Power Company | E-01933A-04-0408 | Residential Utility Consumer Office |
| Arizona-American Water Company | W-1303A-05-0280 | Residential Utility Consumer Office |
| Southwest Gas Corporation | G-01551A-04-0876 | Residential Utility Consumer Office |
| Arizona-American Water Company | W-1303A-05-0405 | Residential Utility Consumer Office |
| Arizona-American Water Company | W-1303A-05-0718 | Residential Utility Consumer Office |
| Arizona Public Service Company | E-01345A-06-0009 | Residential Utility Consumer Office |
| Black Mountain Sewer Corporation | SW-02361A-05-0657 | Residential Utility Consumer Office |

| Utility Company | Docket No. | Client |
|---|---|---|
| Arizona Public Service Company | E-01345A-05-0816 | Residential Utility Consumer Office |
| Arizona-American Water Company | WS-1303A-06-0014 | Residential Utility Consumer Office |
| Tucson Electric Power Company | E-01933A-05-0650 | Residential Utility Consumer Office |
| UNS Gas, Inc. | G-04204A-06-0463 et al. | Residential Utility Consumer Office |
| UNS Electric, Inc. | E-04204A-06-0783 | Residential Utility Consumer Office |
| Arizona-American Water Company | WS-1303A-06-0491 | Residential Utility Consumer Office |
| Arizona-American Water Company | W-1303A-07-0209 | Residential Utility Consumer Office |

# ATTACHMENT MDC-A

**TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSES TO RUCO'S THIRD SET OF DATA REQUESTS DOCKET NO. E-01933A-07-0402 et al. January 4,2008**

| | |
|---|---|
| **3.14** | Please provide an estimate of the revenue to be obtained by the new late payment fees by each customer class of service. |
| **RESPONSE:** | In the process of compiling this response it was discovered that the late payment fees adjustment proposed by the Company contains errors. The Company is attempting to compile the revised adjustment, which will impact the response to this question. The Company will provide the revised adjustment and the response to this question subsequently. |
| **RESPONDENT:** | Dallas Dukes |
| **WITNESS:** | D. Bentley Erdwurm |
| **SUPPLEMENTAL RESPONSE:** | The pro forma adjustment "Mise Service Revenues - Service & Late Fees" contained an error and has been revised. The original adjustment was an increase to test year revenues of $1,308,077. That amount should be revised to $2,469,342. Please see RUCO 3.14 on the enclosed CD for the workpaper for the revised adjustment.. The original "estimate" of new late fee revenue has increased from $363,721 to $1,524,986. TEP estimates that the new late fee revenue will be obtained by each customer class of service as such: |

| | |
|---|---|
| Residential - | 36% |
| Commercial - | 13% |
| Industrial - | 22% |
| Other/ Public Authority - | 29% |

The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

**RESPONDENT:** Dallas Dukes

**WITNESS:** D. Bentley Erdwurm

# ATTACHMENT MDC-B

**TUCSON ELECTRIC POWER COMPANY'S**
**RESPONSES TO**
**RUCO'S EIGHTH SET OF DATA REQUESTS**
**DOCKET NO. E-01933A-07-0402 et al.**
**December 17, 2007**

**8.5** Generation For each year 2004 - 2007 please provide the following information:

a) The percentage of the total annual electricity generated that was generated by each fuel source (i.e. coal, gas, nuclear, etc.)

b) The total annual mwh produced by each fuel source; and

c) The average annual price per mwh produced for each fuel source.

**RESPONSE:** a) Please see the percentage of the total annual electricity generated by each fuel source (i.e., coal, gas, nuclear, etc.) for the years 2004 - 2007 below:

| | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|
| Coal | 86.1% | 84.3% | 81.0% | 75.7% |
| Gas | 3.4% | 2.9% | 6.3% | 7.8% |
| Solar | 0.1% | 0.1% | 0.1% | 0.1% |
| Purchases | 10.4% | 12.7% | 12.6% | 16.4% |
| Total | 100% | 100% | 100% | 100% |

b) Please see the total annual MWh produced by each fuel source for the years 2004 - 2007 below:

| | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|
| Coal | 10,894,000 | 10,847,000 | 10,962,000 | 8,163,000 |
| Gas | 432,000 | 368,000 | 850,000 | 841,000 |
| Solar | 8,000 | 9,000 | 9,000 | 6,000 |
| Purchases | 1,322,000 | 1,639,000 | 1,707,000 | 1,772,000 |
| Total | 12,656,000 | 12,863,000 | 13,528,000 | 10,782,000 |

**TUCSON ELECTRIC POWER COMPANY'S**
**RESPONSES TO**
**RUCO'S EIGHTH SET OF DATA REQUESTS**
**DOCKET NO. E-01933A-07-0402 et al.**
**December 17,2007**

c) Please see the average annual price per MWh produced for each fuel source for the years 2004 - 2007 below:

| | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|
| Coal | $ 16.43 | $ 17.52 | $ 17.79 | $ 19.36 |
| Gas | 78.70 | 97.83 | 64.71 | 73.72 |
| Purchases | 55.22 | 79.93 | 60.34 | 64.90 |
| Average Total | $ 22.61 | $ 27.77 | $ 26.11 | $ 31.09 |

**RESPONDENT:** Kevin Battaglia

**WITNESS:** David Hutchens

**TUCSON ELECTRIC POWER COMPANY**
**DOCKET NO. 01933A-07-0402**
**TABLE OF CONTENTS TO SCHEDULES MDC**

SCHEDULE #

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
OPERATING ADJ#15 - BAD DEBT EXPENSE

DOCKET NO. 01933A-07-0402
SCHEDULE MDC-1

| LINE NO. | DESCRIPTION | AMOUNT | REFERENCE |
|---|---|---|---|
| 1 | NET SALES | $774,470,361 | STF 1.85 |
| 2 | MISCELLANEOUS REVENUES | 2,780,909 | STF 1.85 |
| 3 | SUBTOTAL | 777,251,270 | LINE 1 + LINE 2 |
| 4 | REVENUE ANNUALIZATION | 5,044,631 | STF 1.85 |
| 5 | WEATHER NORMALIZATION | 4,572,055 | STF 1.85 |
| 6 | SERVICE & LATE FEES | 1,308,077 | STF 1.85 |
| 7 | TOTAL REVENUES | 788,176,033 | STF 1.85 |
| 8 | BAD DEBT % WRTITE-OFF | 0.25006% | STF 1.85 |
| 9 | BAD DEBT EXPENSE | 1,970,913 | LINE 7 x LINE 8 |
| 10 | BAD DEBT EXPENSE PER TEP | 2,490,991 | COMPANY W/P |
| 11 | ADJUSTMENT | (520,078) | LINE 9 - LINE 10 |

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
OPERATING ADJ #16 - NAVAJO COAL

DOCKET NO. 01933A-07-0402
SCHEDULE MDC-2

| LINE NO. | DESCRIPTION | AMOUNT | REFERENCE |
|---|---|---|---|
| 1 | T/Y COST PER TON OF NAVAJO COAL | $30.23 | RUCO DR# 2.9 |
| 2 | ACTUAL 2007 COST PER TON | 31.28 | RUCO DR# 2.10 |
| 3 | INCREASE IN COAL COST | 1.05 | LINE 2 - LINE 1 |
| 4 | T/Y TONS | 557,871 | RUCO DR# 2.9 |
| 5 | PROFORMA COST INCREASE | 585,765 | LINE 3 x LINE 4 |
| 6 | PROFORMA COST INCREASE PER COMPANY | 2,780,000 | COMPANY SCHEDULE C-2 |
| 7 | ADJUSTMENT | ($2,194,235) | LINE 5 - LINE 6 |

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

# DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 29, 2008

## TABLE OF CONTENTS

## INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utility regulation and your educational background.

A. I have been involved with utility regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have also been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Tucson Electric Power Company's ("TEP" or "the Company") application for a permanent rate increase ("Application") for the Company's electric service operations in Southern Arizona. TEP filed the Application with the ACC on July 2, 2007. The Company has chosen the calendar year ended December 31, 2006 for the test year in this proceeding.

Q. Briefly describe TEP.

A. TEP is based in Tucson, Arizona and is the second largest investor-owned electric utility in the state of Arizona. The Company provides electric generation, transmission and distribution services to customers in and around the Tucson metropolitan area in Pima County. TEP is a wholly owned subsidiary of UniSource Energy Corporation ("UniSource" or "Parent"), an Arizona corporation, also based in Tucson, that is publicly traded on the New York Stock Exchange ("NYSE")[1]. UniSource also provides natural gas and electric distribution services through two other Arizona subsidiaries: UNS Gas, Inc. ("UNS Gas"), which serves customers in Northern Arizona and Santa Cruz County; and UNS Electric, Inc. ("UNS Electric"), which serves customers in Mohave and Santa Cruz Counties.

[1] NYSE ticker symbol UNS.

Q. Please explain your role in RUCO's analysis of TEP's Application.

A. I reviewed TEP's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of debt (the Company has no preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving UniSource or TEP?

A. No. In 2003 I was involved with UniSource's acquisition of the gas and electric assets of Citizens' Utilities Company. The aforementioned UNS Gas and UNS Electric subsidiaries of UniSource were the result of that acquisition. During 2005 I provided cost of capital recommendations on TEP's general rate case information filing.[2] The filing was required under the 1999 TEP settlement agreement, approved in Decision No. 62103, and served as a rate check on the Company.[3] More recently I testified on

[2] E-01933A-04-0408

[3] Decision No. 62103 resolved pending litigation on the Commission's Retail Electric Competition Rules and provided TEP with the opportunity to recover stranded costs associated with electric restructuring. The decision also implemented two rate reductions and froze the Company's rates through 2008. TEP entered into the settlement agreement on June 9, 1999 with RUCO, members of Arizonans for Electric Choice and Competition, and the Arizona Community Action Association.

cost of capital issues in rate case proceedings that involved both UNS Gas[4] and UNS Electric[5].

Q. Were you also responsible for conducting an analysis on the Company proposed revenue level, rate base and rate design?

A. No. RUCO Chief of Accounting and Rates Marylee Diaz Cortez, CPA and RUCO analyst Rodney L. Moore will provide testimony on the revenue and rate base aspects of the Company's Application. In addition to RUCO's in-house staff, RUCO has also retained the services of two outside consultants. Glen Gregory, of Garrett Group, LLC, will testify on RUCO's rate design and cost of service recommendations and Ben Johnson, Ph.D. of Ben Johnson Associates, will present RUCO's positions on the various competitive scenarios that TEP is proposing in this case.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

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[4] Docket No. G-04204A-06-0463

[5] Docket No. E-04204A-06-0783

**SUMMARY OF TESTIMONY AND RECOMMENDATIONS**

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this second section I will also provide a brief overview of the current economic climate that TEP is operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on TEP' cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of TEP, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.44 percent cost of equity capital. This 9.44 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies.

Cost of Debt – I am recommending that the Commission adopt the Company-proposed 6.39 percent cost of long-term debt. This is based on my review of the costs associated with the various debt instruments issued by TEP to finance the Company's plant-in-service.

Capital Structure – I am recommending that the Company-proposed pro forma capital structure, which is comprised of 55.0 percent long-term debt and 45.0 percent common equity, be adopted by the Commission.

Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, and cost of debt analyses, I am recommending a 7.76 percent cost of capital for TEP. This figure represents the weighted cost of my recommended cost of common equity and my recommended costs of short and long-term debt.

...

Q. Why do you believe that your recommended 7.76 percent cost of capital is an appropriate rate of return for TEP to earn on its invested capital?

A. The 7.76 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

...

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as TEP, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

**COST OF EQUITY CAPITAL**

Q. What is your recommended cost of equity capital for TEP?

A. Based on the results of my DCF and CAPM analyses, which ranged from 8.63 percent to 11.08 percent for a sample of electric providers, I am recommending a 9.44 percent cost of equity capital for TEP. My recommended 9.44 percent figure represents a mean average of the results of my DCF and CAPM analyses, which utilized a sample of publicly traded electric companies.

...

**Discounted Cash Flow (DCF) Method**

Q. Please explain the DCF method that you used to estimate TEP's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = ( D_1 \div P_0 ) + g$$

where: $k$ = the required return (cost of equity, equity capitalization rate),

$D_1 \div P_0$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

$g$ = the expected rate of future dividend growth.

This formula is the basis for the standard growth valuation model that I used to determine TEP's cost of equity capital. It is similar to one of the models used by the Company.

Q. In determining the rate of future dividend growth for TEP, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[6]

Table I

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Growth |
|---|---|---|---|---|---|---|
| Book Value | $10.00 | $10.40 | $10.82 | $11.25 | $11.70 | 4.00% |
| Equity Return | 10% | 10% | 10% | 10% | 10% | N/A |
| Earnings/Sh. | $1.00 | $1.04 | $1.082 | $1.125 | $1.170 | 4.00% |
| Payout Ratio | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | N/A |
| Dividend/Sh | $0.60 | $0.624 | $0.649 | $0.675 | $0.702 | 4.00% |

[6] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony of Stephen G. Hill, dated December 10, 1993, pages 25 - 32.

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as $g = b \times r$, is also referred to as the internal or sustainable growth rate.

...

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Growth |
|---|---|---|---|---|---|---|
| Book Value | $10.00 | $10.40 | $10.82 | $11.47 | $12.158 | 5.00% |
| Equity Return | 10% | 10% | 15% | 15% | 15% | 10.67% |
| Earnings/Sh | $1.00 | $1.04 | $1.623 | $1.720 | $1.824 | 16.20% |
| Payout Ratio | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | N/A |
| Dividend/Sh | $0.60 | $0.624 | $0.974 | $1.032 | $1.094 | 16.20% |

In the example displayed in Table II, a sustainable growth rate of four percent[7] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[8] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be

[7] [ ( Year 2 Earnings/Sh – Year 1 Earnings/Sh ) ÷ Year 1 Earnings/Sh ] = [ ( $1.04 - $1.00 ) ÷ $1.00 ] = [ $0.04 ÷ $1.00 ] = 4.00%

[8] [ ( 1 – Payout Ratio ) x Rate of Return ] = [ ( 1 - 0.60 ) x 15.00% ] = 0.40 x 15.00% = 6.00%

used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change only in the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

…

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[9] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: $g$ = DCF expected growth rate,

$b$ = the earnings retention ratio,

$r$ = the return on common equity,

$s$ = the fraction of new common stock sold that

[9] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

accrues to a current shareholder, and

v = funds raised from the sale of stock as a fraction of existing equity.

and v = 1 - [ ( BV ) ÷ ( MP ) ]

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In the most recent Southwest Gas Corporation rate case[10], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group consisting of eight electric utility companies that have similar operating characteristics to TEP.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of TEP?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with TEP itself. Although shares of TEP's parent company, UniSource, are traded on the NYSE, there is no financial data available on dividends paid on *publicly held* shares of TEP. Consequently it was

[10] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

necessary to create a proxy by analyzing publicly traded electric companies with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your proxy for TEP?

A. With the exception of two electric companies, I chose the same sample of electric providers that were used by TEP's cost of capital witness, Samuel C. Hadaway, Ph. D. All of the electric utility companies in my sample, with the exception of MG Energy Inc., are publicly traded on the NYSE and are followed by The Value Line Investment Survey's ("Value Line") electric utility (east, central and west) industry segments. MG Energy Inc. is traded on the NASDAQ[11] which is also a major U.S. stock exchange. Each of the companies in the proxy are engaged in the provision of

[11] National Association of Securities Dealers Automated Quotation system

regulated electric utility services. Attachment A of my testimony contains Value Line's most recent evaluation of the regional electric utility proxy group that I used for my cost of common equity analysis.

Q. What companies are included your proxy?

A. Schedule WAR-2 lists the twenty-six electric service providers included in my proxy and their NYSE/NASDAQ ticker symbols.

Q. Did the Company's witness also perform a similar analysis using electric utility companies?

A. Yes. As I noted earlier, the Company's witness, Dr. Hadaway, performed a similar analysis that used all but two of the publicly traded electric utility companies included in my sample.

Q. What two electric companies did you exclude from your sample?

A. My sample excludes Energy East Corporation (NYSE symbol EAS), and Puget Energy, Inc. (NYSE symbol PSD).

Q. Why did you exclude these two electric service providers from your sample?

A. Both of these electric service providers have accepted takeover offers from other firms. On November 20, 2007, Energy East Corporation shareholders agreed to be acquired by Iberdrola, S.A., a large utility holding company based in Spain. Puget Energy, Inc. announced the acceptance of an offer from a consortium formed by Macquarie Infrastructure Partners and Diversified Utility and Energy Trusts on October 26, 2007. Because the stock prices of these two companies are now being driven by the offers of their respective buyers, they are no longer suitable for my sample of electric providers.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2002 to 2006. Schedule WAR-5 also includes Value Line's projected 2007, 2008 and 2010-12 values for the retention ratio, return on book equity, book value per share growth rate, and number of shares outstanding for the electric utility companies in my sample.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use Hawaiian Electric Industries, Inc., (NYSE symbol HE) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 9 and 10 of my testimony) to multiply HE's earned return on common equity by its earnings retention ratio for each year in the 2002 to 2006 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, HE's sustainable internal growth rate ranged from 2.65% in 2002 to 0.67% in 2006. The company's growth rates experienced a declining pattern during the majority of the observation period, which resulted in a 1.58 percent average over the 2002 to 2006 time frame. Value Line's analysts are forecasting a negative retention ratio for 2007 before HE's sustainable growth rate falls to 0.07% during 2008. Value Line's analysts are also projecting that the declining trend will reverse and expects a sustainable growth rate of 1.91% during the 2010-12 period. Value Line has also revised its book value growth projection upward from negative 1.00% in November 2007 to negative 0.50%. Based on the aforementioned projections and estimates, I believe that a 1.75% rate of internal sustainable growth is reasonable for HE.

...

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that HE's share growth averaged 2.56% over the 2002 - 2006 observation period. However, Value Line expects future outstanding shares to increase modestly from 83.50 million in 2006 to 87.00 million by the end of 2012. Taking this data into consideration, I am estimating a 2.00 percent rate of share growth for HE.

My final dividend growth rate estimate for HE is 2.41 percent (1.75 percent internal + 0.66 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample electric utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 4.30 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. As can be seen in Schedule WAR-6, my 4.30 percent estimate is 133 basis points higher than the 2.97 percent average of Value Line's and Zacks Investment Research's ("Zacks") projected and historic averages of earnings per share, dividends per share and book value per share. My 4.30 percent estimate is also 223 basis points higher than Value Line's

2.07 percent 5-year historic compound history. Both the Value Line and Zacks earnings projections (Attachment B) indicate that investors are expecting increased performance from electric utility companies in the future. Based on the information presented in Schedule WAR-6, I would say that my 4.30 percent estimate, which is very close to Value Line's projected growth estimate (also based on an average of earnings per share, dividends per share and book value per share) is a fair representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's most recent (i.e. February 8, 2008, December 28, 2007 and November 30, 2007) Ratings and Reports for the Electric Utility (West, Central and East) Industry updates. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period December 10, 2007 to February 8, 2008.

...

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric utilities included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 8.62 percent.

**Capital Asset Pricing Model (CAPM) Method**

Q. Please explain the theory behind the capital asset pricing model ("CAPM") and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[12], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[13] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that

[12] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[13] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (r_m - r_f)\, ]$$

where: $k$ = cost of capital of a given security,

$r_f$ = risk-free rate of return,

$ß$ = beta coefficient, a statistical measurement of a security's systematic risk,

$r_m$ = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average on a 91-day Treasury Bill ("T-Bill") rate.[14] This resulted in a risk-free ($r_f$) rate of return of 2.68 percent.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. Because a 91-day T-Bill presents the lowest possible total risk to an investor. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of the historical yields of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[15] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor.

[14] A six-week average was computed for the current rate using 91-day T-Bill quotes listed in Value Line's Selection and Opinion newsletter from January 11, 2008 to February 15, 2008.

[15] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2006 as the proxy for the market rate of return ($r_m$). The information was obtained from Morningstar's SBBI Yearbook, which publishes historical data on stock returns, U.S. Treasury yields and rates of inflation. The risk premium ($r_m$ - $r_f$) that results by using the geometric mean calculation for $r_m$ is equal to 7.72 percent (10.40% - 2.68% = 7.72%). The risk premium that results by using the arithmetic mean calculation for $r_m$ is 9.62 percent (12.30% - 2.68% = 9.62%).

Q. How did you select the beta coefficients that were used in your CAPM model?

A. The beta coefficients (ß), for the electric utilities used in my proxy, were calculated by Value Line and were published in the most recent updates (i.e. February 8, 2008, December 28, 2007 and November 30, 2007) for the West, Central and East regional electric providers in my sample. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDC's included in my sample ranged from 0.70 to 1.15 with an average beta of 0.87.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for $r_m$ results in an average expected return of 9.42 percent. My calculation using an arithmetic mean results in an average expected return of 11.08 percent.

...

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

| **METHOD** | **RESULTS** |
|---|---|
| DCF | 8.62% |
| CAPM | 9.42% – 11.08% |

Based on these results, my best estimate of an appropriate range for a cost of common equity for TEP is 8.62 percent to 11.08 percent. My final recommendation for TEP is 9.44 percent.

Q How did you arrive at your recommended 9.44 percent cost of common equity?

A. My recommended 9.44 percent cost of common equity is the average of my DCF and CAPM results. The calculation can be seen on Page 3 of Schedule WAR-1.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. Dr. Hadaway is recommending an 11.75 percent cost of equity for TEP's actual test year capital structure and a 10.75 percent cost of equity for the Company-proposed pro forma (i.e. hypothetical) capital structure. Dr.

Hadaway's 11.75 percent cost of equity capital, for TEP's actual test year capital structure, is 231 basis points higher than the 9.44 percent cost of equity capital that I am recommending. Dr. Hadaway's 10.75 percent cost of equity capital, for the Company-proposed pro forma capital structure, is 131 basis points higher than the 9.44 percent cost of equity capital that I am recommending.

**Current Economic Environment**

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[16] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

[16] The interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the current recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in 45 years.

Even though some signs of economic strength, that were mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[17]"

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25

[17] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[18] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[19]

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[20]. Since it began increasing the federal funds rate in June 2004, the Fed has assured investors that it

[18] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[19] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

[20] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[21]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

Q. Was the Fed's attempt to engineer a soft landing successful during this period?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low;

[21] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[22]

Q. What has been the state of the economy over the past year?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[23] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession were beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crises, rooted in a deterioration of the market for U.S. subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market

[22] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

[23] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

operations) into the credit markets.[24] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal,[25] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points or 25 basis points more than what was anticipated. This brought the federal funds rate down to a level of 4.75 percent. The Feds action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175

[24] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[25] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

basis points to its current level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's last meeting on January 29, 2008.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. Despite the increases (prior to June 2006) by the FOMC, interest rates and yields on U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 3.50 percent from 5.73 percent in 2000.

Q. What has been the trend in other leading interest rates over the last year?

A. As of February 15, 2008, the leading interest rates have all dropped from the levels that existed a year ago (Attachment C). The prime rate has fallen from 8.25 percent a year ago to its current level of 6.00 percent. The benchmark federal funds rate, just discussed, has decreased from 5.25 percent, in February 2007, to its current level of 3.00 percent (the result of the Fed's recent series of interest rate cuts described earlier). The yields on several maturities of U.S. Treasury instruments have also decreased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[26], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, appears to have ended and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 91-day T-bill rate, used in my CAPM analysis, has fallen from 5.15 percent, in February 2007, to 2.09 percent as of February 6, 2008. The 1-Year Treasury constant maturity rate also decreased from 5.07 percent over the past year to 2.06 percent. Again, for the most part, these current yields are considerably lower than corresponding yields that existed during the early nineties (as can be seen on Schedule WAR-8).

Q. What is the current outlook for interest rates, inflation, and the economy?

A. According to The Wall Street Journal's current February 2008 Economic Forecasting Survey, the federal funds rate is expected to fall from its current level of 3.00 percent to approximately 2.64 percent by December 2008. The change in the consumer price index, a key measure of inflation, is also expected to fall from the December 2007 level of 4.10 percent to 2.30 percent by December 2008.

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[26] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

Value Line's analysts had this to say in their Economic and Stock Market Commentary that appeared in the February 15, 2008 edition of Value Line's Selection and Opinion publication:

> **The economic weakness might continue for a while.** Unfortunately, the likely further deterioration in the employment and housing outlooks may push back the timetable for even a mild economic recovery until late in the year. For now, we think there is a good chance that we will see either no growth in the U.S. gross domestic product during the first quarter or, more likely, a modest decline. (By comparison, the nation's GDP posted a negligible gain of 0.6% in last year's fourth quarter.) Another tepid showing is likely in the second quarter, when economic growth might resume, but on a nominal basis. Thereafter, we would expect to see some benefits from recent and likely future moves by the Federal Reserve to cut interest rates. However, a resumption of the strong economic growth that we saw earlier in this decade may not take hold until 2009 or, more likely, 2010.

Q. How has the current economic environment of lower interest rates affected the electric utility industry as a whole?

A. Value Line analyst Nils C. Van Liew took note of the environment of low interest rates that existed in the early part of 2007. In Value Line's Electric Utility (East) Industry update dated March 2, 2007, Mr. Van Liew had this to say:

> **Low Interest Rates.** Several factors are, no doubt, driving the electric utilities' strong share-price performance. Perhaps most important is a benign interest-rate environment. Utilities frequently tap the credit markets to fund their operations. (Low interest rates mean they can cost effectively build new power plants and maintain existing ones.) "Cheap money" also tends to drive economic expansion, thereby increasing electricity demand. That said, interest rates should remain relatively low, though the likelihood that the Federal Reserve eases (monetary) policy is small, given persistent inflation concerns.

Given the fact that interest rates are even lower now than they were at the time of Mr. Van Liew's writing, and utility bond rates are currently lower than their 2007 averages, I believe that his views are still valid.

Q. What are the current dividend yields of electric utility stocks followed by Value Line?

A. In the February 8, 2008 Electric Utility (West) Industry update, Value Line analyst Paul E. Debbas, CFA, observed that, following a recent decline in electric utility stock prices, the average yield of the fifty-eight stocks in the Electric Utility Industry, followed by Value Line, is now 3.90 percent which is still low by historical standards but is higher than the group's 3.50 percent to 3.60 percent average yield for most of the past two to three years. Mr. Debbas went on to state that there are some stocks of solid utilities that now have yields of nearly 5.00 percent which offer good dividend-growth potential.

Q. How does the 3.90 percent average yield on the fifty-eight electric utility stocks noted above compare with the average dividend yield of your sample electric utility companies?

A. As can be seen in Schedule WAR-3, my sample electric utility companies have an average dividend yield of 4.32 percent which is 42 basis points higher than the 3.90 percent average yield on electric utility stocks reported by Value Line's Mr. Debbas.

...

Q. After weighing the economic information that you've just discussed, do you believe that the 9.44 percent cost of equity capital that you have estimated is reasonable for TEP?

A. I believe that my recommended 9.44 percent cost of equity will provide TEP with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are low by historical standards), a possible rebound in growth in new housing construction (attributed to the recent cuts in interest rates), and the Fed's ability to keep inflation in check are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return.

**COST OF DEBT**

Q. Have you reviewed TEP's testimony on the Company-proposed cost of debt?

A. Yes, I have reviewed the testimony prepared by Kevin P. Larson, Senior Vice President, Chief Financial Officer and Treasurer of UniSource Energy ad TEP.

...

Q. Do you agree with Mr. Larson's inclusion of the amortized debt discount and expenses and losses attributed to reacquired debt and the credit facility fees to arrive at his final cost of long-term debt figure of 8.22 percent?

A. Yes.

Q. What is your recommended cost of long-term debt?

A. I am recommending the Company-proposed cost of long-tem debt of 6.39 percent.

**CAPITAL STRUCTURE**

Q. Have you reviewed TEP's testimony regarding the Company's proposed capital structure?

A. Yes, I have reviewed the direct testimony of Company witness Larson, who also testified on TEP's proposed capital structure.

Q. What was TEP's actual capital structure during the test year?

A. TEP's actual capital structure during the test year was comprised of 60.1 percent debt and 39.9 percent equity.

...

Q. What capital structure is the Company proposing in this proceeding?

A. The Company is proposing a pro forma, or hypothetical, capital structure comprised of 55.0 percent long-term debt and 45.0 percent common equity.

Q. What capital structure are you proposing for TEP?

A. I am recommending the same hypothetical capital structure being proposed by TEP.

Q. Is the capital structure proposed by TEP in line with industry averages?

A. No. As can be seen in Schedule WAR-9, the capital structure proposed by TEP is higher in debt than the average capital structure of the electric utility companies included in my sample. The companies in my sample have capital structures comprised of approximately 50.0 percent debt and 50.0 percent equity.

Q. In terms of risk, how does your recommended capital structure compare to the electric utility companies in your sample?

A. The electric utility companies in my sample would be considered as having a slightly lower level of financial risk (i.e. the risk associated with debt repayment) because of their lower levels of debt. The lower financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the cost of equity derived in my DCF analysis is applicable to companies that are not as leveraged and, theoretically speaking, not as risky as a utility with a level of debt similar to TEP's. In the case of a publicly traded company, such as those included in my proxy, a company with TEP's level of debt would be perceived as having a slightly higher level of financial risk and would therefore also have a slightly higher expected return on common equity.

Q. Have you made any upward adjustment to your recommended cost of equity that takes TEP's higher level of financial risk into consideration?

A. No. I believe that my recommended hypothetical capital structure which increases TEP's percentage of equity from 39.9 percent to 45.0 percent will provide the Company with additional cash flows to mitigate any concerns regarding financial risk. In addition to providing TEP with additional operating income, my recommended hypothetical capital structure will also provide TEP with a higher level of income tax expense.

Q. Please explain how your recommended hypothetical capital structure will provide TEP with additional cash flow through a higher level of income tax expense.

A. The lower level of debt in my recommended capital structure produces a lower interest deduction for the income tax calculation thus providing TEP with a higher level of income tax expense than what would result if the Company's higher actual level of deductible interest were used in the calculation. As a result of this the Company's actual income tax expense is lower than the income tax calculated for ratemaking purposes thus providing TEP with additional cash. For the reasons stated above I have decided not to make any upward adjustment on my recommended 9.44 percent cost of common equity.

## WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. The Company has proposed a weighted cost of capital of 8.35 percent. This composite figure is the result of the Company-proposed hypothetical capital structure that produces a weighted average of 3.51 percent for long-term debt and a weighted cost of common equity of 4.84 percent. The Company-proposed 8.35 percent weighted cost of capital is 59 basis points higher than the 7.76 percent weighted cost of capital that I am recommending, which is the weighted cost of my recommended 6.39 percent cost of long-term debt and 9.44 percent cost of common equity.

## COMMENTS ON TEP'S COST OF EQUITY CAPITAL TESTIMONY

Q. Have you reviewed TEP's testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony prepared by Dr. Samuel C. Hadaway.

Q. Please compare the Company-proposed cost of equity with your recommended cost of equity.

A. The Company is recommending a cost of equity capital of 10.75 percent in conjunction with a hypothetical capital structure comprised of 55.0 percent debt and 45.0 percent equity. The Company-proposed 10.75 percent cost of equity is the low end of a 10.75 percent to 11.75 percent range of estimates recommended by Dr. Hadaway. The Company-proposed 10.75 percent cost of equity is 131 basis points higher than my recommended 9.44 percent cost of equity.

Q. Have you studied the specific methods that Company witness Hadaway used to derive the Company-proposed cost of equity capital?

A. Yes.

Q. What methods did Dr. Hadaway use to arrive at his cost of common equity for TEP?

A. Dr. Hadaway used the DCF, CAPM and risk premium methods to estimate TEP's cost of common equity.

Q. Can you provide a comparison of the results derived from Dr. Hadaway's models and yours?

A. Yes.

**DCF Comparison**

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Dr. Hadaway conducted his?

A. Yes, In addition to the constant growth model that I used to estimate TEP's cost of equity, Dr. Hadaway also relied on the results of a multi-stage DCF model that used the proxy of twenty-eight electric utility companies that I described earlier in my testimony.

Q. Please compare Dr. Hadaway's constant growth DCF estimate to your constant growth DCF estimate.

A. Dr. Hadaway used two versions of the constant growth DCF model; what he refers to as his traditional constant growth DCF model, and a constant growth DCF model that uses a 6.60 percent estimate of gross domestic product ("GDP") figure for the growth component ("g") of the model. His traditional constant growth DCF model produces an estimate of 9.50 percent which is 88 basis points higher than my 8.66 percent estimate. Dr. Hadaway's constant growth DCF model that uses the aforementioned 6.60 percent GDP figure produces an estimate of 10.80 percent which is 218 basis points higher than my average 8.62 percent estimate. Dr. Hadaway ignores the lower estimate of 9.50 percent produced by his traditional version of the DCF model because it falls below the results produced by his other models used to estimate TEP's cost of common equity.

Q What created the 88 basis point difference between Dr. Hadaway's traditional constant growth DCF model estimate and your constant growth DCF model?

A. Dr. Hadaway's average dividend yield component ("$D_1 \div P_0$") of 4.15 percent is actually 17 basis points lower than my 4.32 percent figure. This is mainly attributed to an overall decline in the stock prices ("$P_0$") of the electric utilities included in our samples. Since Dr. Hadaway's average dividend estimate ("$D_1$") of $1.54 is just slightly higher than my average of $1.53, his higher average stock price of $37.18 produces a lower yield than my average stock price of $36.32. Thus the main reason for the difference in our constant growth DCF estimates is Dr. Hadaway's growth estimate which is the sum of a company's internal sustainable growth (br) and its external growth ( sv ) estimate.

Q. Can you explain why Dr. Hadaway's growth estimate is higher than yours?

A. Yes. Dr. Hadaway performed a b x r calculation that produced an internal sustainable growth rate figure of 3.90 percent which was 7 basis points higher than my 3.83 percent figure. However, he forgoes the type of s x v calculation (based on estimates of share growth) that I have performed and instead uses an average comprised of his b x r figure, Zack's 5-year earnings estimate, Value Line's 5-year earnings estimate and his 6.60 percent GDP figure. This produces a growth estimate of 5.39 percent which is 109 basis points higher than my growth estimate of 4.30 percent.

Q. Do you agree with Dr. Hadaway's use of long-term GDP growth in his models?

A. No. I do not. The use of the GDP estimate assumes that the long-term growth rate for the electric-utilities in his sample will be a combination of analysts' long-term growth rate projections and the growth rate of all goods and services produced by labor and property in the U.S., as opposed to relying on growth information that is specific to the electric companies included in our respective samples.

Q. Is this the same reason why Dr. Hadaway's second constant growth DCF estimate, that uses his 6.60 percent estimate of GDP for the growth component, is 218 basis points higher than your average 8.62 percent estimate?

A. Yes. Once again Dr. Hadaway's average dividend yield component of 4.15 percent is actually 17 basis points lower than my 4.32 percent figure. However, his growth component is the higher 6.60 percent GDP figure discussed above. The use of the 6.0 percent GDP figure as his growth estimate produces the 10.80 percent constant growth DCF result that Dr. Hadaway used in making his final cost of equity estimate for TEP.

...

Q. What is the difference between Dr. Hadaway's multi-stage DCF estimate and your single-stage constant-growth DCF estimate?

A. Dr. Hadaway's average multi-stage DCF estimate of 10.40 percent is 96 basis points higher than the 9.44 percent estimate produced by my single-stage constant growth model.

Q. Please describe the multi-stage DCF model used by Dr. Hadaway.

A. The multi-stage DCF model is comprised of three components: a dividend yield component similar to the one used in the constant growth model, a near-term (i.e. 5-year) growth estimate that is also similar to the one used in the constant growth DCF and a long-term growth estimate that is calculated into perpetuity through the use of an internal rate of return calculation on a computer spreadsheet. In this case, Dr. Hadaway used the same 6.60 percent GDP figure, discussed earlier, as the long-term growth estimate in the second-stage component of his multi-stage model.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Dr. Hadaway?

A. Primarily because the growth rate component that I estimated for my single-stage model already takes into consideration 5-year long-term growth rate projections that are specific to the electric utilities included in my proxy as opposed to a GDP figure that assumes that an electric utility will grow at the same rate of growth of all goods and services produced in the U.S. The 5-year period is in line with the number of years that a utility will file for rate relief as opposed to a GDP rate of growth that is calculated into perpetuity and inflates a utility's cost of equity capital.

**CAPM Comparison**

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Dr. Hadaway conducted his?

A. The main differences between Dr. Hadaway's CAPM analysis and mine are the Treasury instruments that we relied on for the risk-free rate of return and the average beta coefficient that was used in our models. Dr. Hadaway performed a long-term CAPM analysis and a short-term CAPM analysis.

Q. What Treasury instruments did Dr. Hadaway use as a proxy for the risk free (i.e. $r_f$) rate in his CAPM model?

A. Dr. Hadaway used the 30-year U.S. Treasury Constant Maturity Rate of 5.01 percent, as of May 27, 2007, in his long-term CAPM analysis. For his short-term CAPM analysis he used the 3-month U.S. Treasury Secondary Market Rate of 4.89 percent.

...

Q. What are the current yields on the 30-year U.S. Treasury Constant Maturity Rate and the 3-month U.S. Treasury Secondary Market Rate that Dr. Hadaway used in his CAPM models?

A. As of the week ending February 8, 2008 the yield on the 30-year U.S. Treasury Constant Maturity Rate stood at 4.40 percent which is 67 basis points lower than the 5.07 percent rate used in Dr. Hadaway's long-term CAPM model. The yield on the 3-month U.S. Treasury Secondary Market Rate stood at 2.14 percent which is 275 basis points lower than the 4.89 percent rate used in Dr. Hadaway's long-term CAPM model.

Q. Did Dr. Hadaway use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However the average of Value Line's beta's for the electric utility companies in our samples proxies have decreased since Dr. Hadaway filed his direct testimony. The mean average of the Value Line betas used by Dr. Hadaway is 0.91 as opposed to my average beta of 0.87 (the elimination of Energy East Corporation and Puget Energy, Inc. from my sample had no effect on my average beta).

Q. What was the difference between Dr. Hadaway's market risk premiums and your market risk premiums?

A. Dr. Hadaway used market risk premiums of 5.75 percent and 7.60 percent for his respective long-term and short-term CAPM models. I used market risk premiums of 7.72 percent and 9.62 percent in my respective CAPM models using geometric and arithmetic means.

Q. What would Dr. Hadaway's expected returns be if his CAPM models were updated to include the aforementioned changes in Treasury yields and average beta coefficients?

A. An update of Dr. Hadaway's CAPM models using current Treasury instrument yields an average beta of 0.87 percent would produce expected returns of 9.41 percent in his long-term model and 8.76 percent in his short-term model. His average CAPM estimate would be 9.09 percent or 116 basis points lower than my 10.25 percent average estimate. Dr. Hadaway's revised CAPM estimates would fall into the same category as his traditional constant growth DCF estimate which he ignored because it fell below the results produced by his other models used to estimate TEP's cost of common equity.

Q. How do these results compare to TEP's parent, UniSource, on a stand alone basis?

A. TEP's parent, UniSource, has a Value Line beta of 0.60 which is lower than both the range (0.70 to 1.15) and the mean average (0.87) of the betas included in my CAPM sample. What this means is that, in terms of beta, UniSource is a lower investment risk than the twenty-six electric utilities that made up my CAPM sample which included all but two of the companies in Dr. Hadaway's CAPM sample.

Using UniSource's 0.65 beta, the aforementioned current 4.40 percent long-term and 2.14 percent short-term Treasury yields, and Dr. Hadaway's long-term and short-term market risk premiums of 5.75 percent and 7.60 percent respectively produces expected returns of 7.85 percent (long-term) and 6.70 percent (short-term) for UniSource on a stand-alone basis). This is 246 to 511 basis points lower than the original expected returns presented in Dr. Hadaway's direct testimony, and 156 to 206 basis points lower than my 9.41 percent long-term and 8.76 percent short-term update of Dr. Hadaway's CAPM results.

Q. Did you perform a risk premium analysis similar to the one performed by Dr. Hadaway?

A. No I did not.

**Final Cost of Equity Estimate**

Q. How did TEP arrive at the Company-proposed 10.75 percent cost of equity capital?

A. The Company adopted the low end of Dr. Hadaway's recommended 10.75 to 11.75 range of cost of equity estimates.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Dr. Hadaway or any other witness for TEP constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on TEP?

A. Yes, it does.

# Qualifications of William A. Rigsby, CRRA

**EDUCATION:**

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

**EXPERIENCE:**

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

Appendix 1

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| ICR Water Users Association | U-2824-94-389 | Original CC&N |
| Rincon Water Company | U-1723-95-122 | Rate Increase |
| Ash Fork Development Association, Inc. | E-1004-95-124 | Rate Increase |
| Parker Lakeview Estates Homeowners Association, Inc. | U-1853-95-328 | Rate Increase |
| Mirabell Water Company, Inc. | U-2368-95-449 | Rate Increase |
| Bonita Creek Land and Homeowner's Association | U-2195-95-494 | Rate Increase |
| Pineview Land & Water Company | U-1676-96-161 | Rate Increase |
| Pineview Land & Water Company | U-1676-96-352 | Financing |
| Montezuma Estates Property Owners Association | U-2064-96-465 | Rate Increase |
| Houghland Water Company | U-2338-96-603 et al | Rate Increase |
| Sunrise Vistas Utilities Company – Water Division | U-2625-97-074 | Rate Increase |
| Sunrise Vistas Utilities Company – Sewer Division | U-2625-97-075 | Rate Increase |
| Holiday Enterprises, Inc. dba Holiday Water Company | U-1896-97-302 | Rate Increase |
| Gardener Water Company | U-2373-97-499 | Rate Increase |
| Cienega Water Company | W-2034-97-473 | Rate Increase |
| Rincon Water Company | W-1723-97-414 | Financing/Auth. To Issue Stock |
| Vail Water Company | W-01651A-97-0539 et al | Rate Increase |
| Bermuda Water Company, Inc. | W-01812A-98-0390 | Rate Increase |
| Bella Vista Water Company | W-02465A-98-0458 | Rate Increase |
| Pima Utility Company | SW-02199A-98-0578 | Rate Increase |

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| Pineview Water Company | W-01676A-99-0261 | WIFA Financing |
| I.M. Water Company, Inc. | W-02191A-99-0415 | Financing |
| Marana Water Service, Inc. | W-01493A-99-0398 | WIFA Financing |
| Tonto Hills Utility Company | W-02483A-99-0558 | WIFA Financing |
| New Life Trust, Inc. dba Dateland Utilities | W-03537A-99-0530 | Financing |
| GTE California, Inc. | T-01954B-99-0511 | Sale of Assets |
| Citizens Utilities Rural Company, Inc. | T-01846B-99-0511 | Sale of Assets |
| MCO Properties, Inc. | W-02113A-00-0233 | Reorganization |
| American States Water Company | W-02113A-00-0233 | Reorganization |
| Arizona-American Water Company | W-01303A-00-0327 | Financing |
| Arizona Electric Power Cooperative | E-01773A-00-0227 | Financing |
| 360networks (USA) Inc. | T-03777A-00-0575 | Financing |
| Beardsley Water Company, Inc. | W-02074A-00-0482 | WIFA Financing |
| Mirabell Water Company | W-02368A-00-0461 | WIFA Financing |
| Rio Verde Utilities, Inc. | WS-02156A-00-0321 et al | Rate Increase/ Financing |
| Arizona Water Company | W-01445A-00-0749 | Financing |
| Loma Linda Estates, Inc. | W-02211A-00-0975 | Rate Increase |
| Arizona Water Company | W-01445A-00-0962 | Rate Increase/ACRM |
| Mountain Pass Utility Company | SW-03841A-01-0166 | Financing |
| Picacho Sewer Company | SW-03709A-01-0165 | Financing |
| Picacho Water Company | W-03528A-01-0169 | Financing |
| Ridgeview Utility Company | W-03861A-01-0167 | Financing |
| Green Valley Water Company | W-02025A-01-0559 | Rate Increase |
| Bella Vista Water Company | W-02465A-01-0776 | Rate Increase |
| Arizona Water Company | W-01445A-02-0619 | Rate Increase/ACRM |

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| Arizona-American Water Company | W-01303A-02-0867 et al. | Rate Increase |
| Arizona Public Service Company | E-01345A-03-0437 | Rate Increase |
| Rio Rico Utilities, Inc. | WS-02676A-03-0434 | Rate Increase |
| Qwest Corporation | T-01051B-03-0454 | Renewed Price Cap |
| Chaparral City Water Company | W-02113A-04-0616 | Rate Increase |
| Arizona Water Company | W-01445A-04-0650 | Rate Increase/ACRM |
| Tucson Electric Power | E-01933A-04-0408 | Rate Review |
| Southwest Gas Corporation | G-01551A-04-0876 | Rate Increase |
| Arizona-American Water Company | W-01303A-05-0405 | Rate Increase/ACRM |
| Black Mountain Sewer Corporation | SW-02361A-05-0657 | Rate Increase |
| Far West Water & Sewer Company | WS-03478A-05-0801 | Rate Increase |
| Gold Canyon Sewer Company | SW-02519A-06-0015 | Rate Increase |
| Arizona Public Service Company | E-01345A-05-0816 | Rate Increase |
| Arizona-American Water Company | W-01303A-06-0014 | Rate Increase |
| Arizona-American Water Company | W-01303A-05-0718 | Transaction Approval |
| UNS Gas, Inc. | G-04204A-06-0463 | Rate Increase |
| Arizona-American Water Company | WS-01303A-06-0403 | Rate Increase |
| Arizona-American Water Company | WS-01303A-06-0491 | Rate Increase |
| UNS Electric, Inc. | E-04204A-06-0783 | Rate Increase |
| Arizona-American Water Company | W-01303A-07-0209 | Rate Increase |

# ATTACHMENT A

# ELECTRIC UTILITY (WEST) INDUSTRY

**All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.**

**Utilities have long had a reputation as a safe haven during downturns in the market. This hasn't been the case in recent weeks.**

**More companies are asking the Nuclear Regulatory Commission for construction and operating licenses for new nuclear units.**

**Since utility stocks have declined, some have become more attractive. But others have merely become less overvalued.**

## Some Safe Haven

Utility stocks have long been known to attract investors for their defensive characteristics in turbulent markets. This held true, for a while, in the recent market turmoil. Eventually, however, electric utility equities "caught up with" the rest of the market. This has been the case even for the stocks of companies that have agreed to be taken over (*Puget Energy*, Energy East, and Aquila). Even the Fed's cut in interest rates didn't help these stocks at all. The Value Line Composite Average and the Value Line Utility Average (which includes stocks of utilities besides electrics) have each declined over 5% since the start of 2008, and the Value Line Utility Average has actually declined a bit more than the Composite Average.

What has caused the decline in this group? Perhaps it was inevitable, given the high valuation of electric utility equities. Many were fully valued or even overvalued after their sharp advances in 2006 and 2007. (Particularly strong were stocks of companies, such as Exelon, Constellation Energy, and Public Service Enterprise Group, that get more than half of their profits from nonregulated activities and thus benefit from high power prices.) Indeed, prior to their recent decline, most electric utility issues were trading within their 2010-2012 Target Price Ranges, and some are *still* trading well within those ranges, even after the downturn. Other concerns are how the weakening economy will affect the demand for electricity—and the prices for power. When the power markets collapsed in 2001 and

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2002, this didn't just occur due to an increase in generating capacity—a sudden decline in electric demand from industrial users was a factor as well. We aren't predicting a repeat of what happened six years ago, but this situation bears watching. The stocks of the three big nonregulated power sellers mentioned above have declined roughly as much as the rest of the group so far this year. Finally, the weakness in the economy could affect state commissions' willingness to grant rate relief to utilities due to the concern about the effect of higher prices on electric customers.

## Nuclear Update

Our November industry report discussed the possibility of nuclear unit construction. Last September, NRG Energy became the first company in 29 years to file a request for a Construction and Operating License (COL). Since then, Duke Energy, Dominion Resources, and the Tennessee Valley Authority have requested COLs. Several other nuclear owners plan to do so in 2008. Each unit would cost many billions of dollars, and even before a shovel ever hits the ground, the application process itself will cost many millions of dollars. We reiterate that, even if a company proceeds with the COL process, this doesn't mean that a new unit or units will be built.

## Investment Advice

Since the recent pullback, the average yield of the 58 stocks in the Electric Utility Industry is now 3.9%. That's still low, by historical standards, but is higher than the group's average yield for most of the past two to three years (which has usually been 3.5%-3.6%). There are some stocks of solid utilities that now have yields of nearly 5% (or higher) and offer good dividend-growth potential. *Pinnacle West*, Progress Energy, Duke Energy, ALLETE, and Vectren are worth mentioning in this regard. The stocks of CH Energy, Great Plains Energy, and Empire District Electric are yielding around 6%, but that's partly because none of these companies has raised the dividend for many years. Not all stocks with high yields are recommended, however. *Hawaiian Electric Industries* has one of the highest yields of any utility equity, but we do not advise its purchase.

*Paul E. Debbas, CFA*

Composite Statistics: ELECTRIC UTILITY INDUSTRY

| 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|
| 277.0 | 288.9 | 325.1 | 336.0 | **350** | **370** | Revenues ($bill) | **440** |
| 18.5 | 20.2 | 22.2 | 25.0 | **27.5** | **29.5** | Net Profit ($bill) | **36.0** |
| 30.4% | 30.4% | 29.6% | 31.9% | **33.5%** | **34.5%** | Income Tax Rate | **34.5%** |
| 4.5% | 3.6% | 3.8% | 4.5% | **6.0%** | **7.0%** | AFUDC % to Net Profit | **4.0%** |
| 58.7% | 56.0% | 54.6% | 52.6% | **51.0%** | **51.0%** | Long-Term Debt Ratio | **49.0%** |
| 39.7% | 42.8% | 44.2% | 46.3% | **48.0%** | **48.0%** | Common Equity Ratio | **50.0%** |
| 418.1 | 426.8 | 432.3 | 447.7 | **465** | **495** | Total Capital ($bill) | **570** |
| 421.3 | 435.2 | 450.3 | 475.0 | **490** | **525** | Net Plant ($bill) | **590** |
| 6.4% | 6.6% | 6.9% | 7.3% | **7.0%** | **7.0%** | Return on Total Cap'l | **7.5%** |
| 10.7% | 10.7% | 11.3% | 11.8% | **11.0%** | **11.0%** | Return on Shr. Equity | **11.5%** |
| 10.8% | 10.9% | 11.5% | 11.9% | **11.5%** | **11.5%** | Return on Com Equity | **11.5%** |
| 4.7% | 4.8% | 4.9% | 5.5% | **5.5%** | **5.0%** | Retained to Com Eq | **5.0%** |
| 58% | 57% | 58% | 55% | **60%** | **60%** | All Div'ds to Net Prof | **59%** |
| 13.7 | 14.8 | 16.3 | 15.7 | *Bold figures are Value Line estimates* | | Avg Ann'l P/E Ratio | **14.5** |
| .78 | .78 | .87 | .85 | | | Relative P/E Ratio | **.95** |
| 4.2% | 3.8% | 3.5% | 3.4% | | | Avg Ann'l Div'd Yield | **3.9%** |

**COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (kwh) | +.3 | +5.4 | +1.3 |
| Average Indust. Use (mwh) | 1384 | 1568 | 1570 |
| Avg. Indust. Revs. per kwh (¢) | 5.25 | 5.73 | 6.17 |
| Capacity at Peak (mw) | NA | NA | NA |
| Peak Load, Summer (mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr.-end) | +1.6 | +1.2 | +1.7 |
| Fixed Charge Coverage (%) | 235 | 253 | 267 |

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

**INDUSTRY TIMELINESS: 65 (of 98)**

**All of the major utilities in the central United States are reviewed in this Issue. Those serving the western region may be found in Issue 11. The eastern companies are covered in Issue 1.**

**Demand for power in the U.S. is rising at an annual rate of 2%. That has resulted in steadily reduced reserve margins and has induced many companies to add generation in the past few years. But utilities are not all using the same fuel sources to meet their obligations. In this report, we discuss a few reasons for the differences.**

### The Dilemma Facing Coal-fired Plants

The U.S. Environmental Protection Agency (EPA) and many state regulatory bodies have taken a strong stand against coal-fired units and are compelling companies to spend large sums to reduce particulate emissions into the atmosphere or close down the facilities. Florida regulators have taken an even more drastic step, by rejecting outright FPL Group's request to build a coal plant because of high capital costs. This forces the company to rely on additional gas-fired units that already account for a large percentage of its fuel mix. In Nevada, a coalition of environmentalists and other parties seeks to derail Sierra Pacific's plan for a new coal plant because renewable resources and energy efficiency programs would be less expensive. The company is contesting the proposal. Still, other utilities have found it economical to reduce emissions in order to keep operating existing units. *Vectren*, for one, is investing large sums in its jointly owned Warrick plant to comply with EPA orders and is improving the efficiency of scrubbers at two other units, rather than looking elsewhere for new energy sources. *Alliant Energy*, for another, is seeking commission approval to add a circulating fluidized coal-fired bed unit, employing a commercially demonstrated clean-coal technology. In addition to reducing toxic emissions, the plant would not only improve import capability but would allow diverse fuel supplies in the boiler.

### Renewable Energy

This source of power includes geothermal, wind, biomass, and solar energy. In 2006, it stood at 7% of total national output. It continues to expand because of high oil and natural gas prices and concern over global warming. To date, some 25 states have enacted legislation requiring utilities to generate a specific percentage of sales from renewable sources. This has stimulated interest in wind power, whose growth has also been driven by a federal production tax credit of 1.9 cents per kilowatt-hour for electricity generated in the first 10 years of a project. The credits are available for systems starting operation by the end of 2008. To beat the deadline, many utilities are constructing wind-powered plants to place them in service before the credit expires. Once the units are in service, the credits are grandfathered. The leader in this field is FPL Group, which has wind plants in 15 states and plans to add another 1,500 megawatts to 2,000 megawatts by 2012. It might be of concern, however, that wind does not provide guaranteed steady output and should be supported by fossil-fueled sources for reliability. Solar power is more predictable. Its one variable is cloud cover, which is not a serious drawback in the Southwest. Twelve states have explicit solar targets. New Mexico's is the largest, with a requirement that 4% of generation come from solar by 2020. But to make this source more efficient, capital costs must be streamlined, because they are currently far more expensive than those of coal.

### The Nuclear Option

Unlike coal-fired plants, nuclear generators pose no environmental concern. Too, the cost of nuclear fuel compares favorably with fossil fuel. Only hydroelectric power is less expensive. Given these pluses, numerous nuclear plant owners have filed for extensions of their operating licenses and are seeking site locations for new units. Among those to do so are Exelon, *Entergy*, and Progress Energy, all three of which are owners of several units. But no new plant will be built until a permanent repository for nuclear waste is serviceable. And the timing of that is still undetermined.

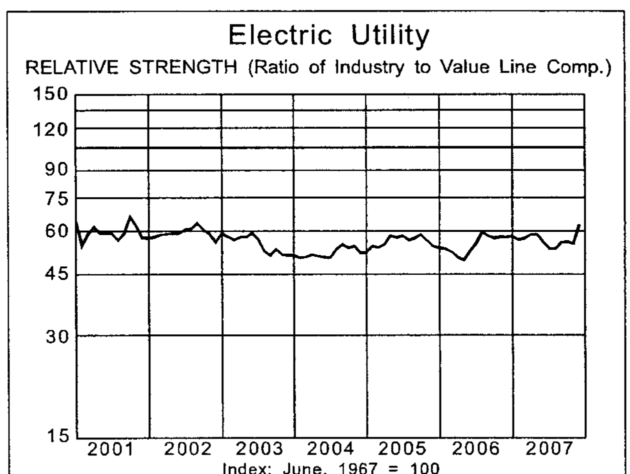
### Investment Advice

The industry's Timeliness rank continues to lag that of most sectors we follow. On the plus side, the average year-ahead yield is almost double that of all dividend-paying companies in the *Value Line* survey. But a note of caution: Many of these utilities are already trading within their 3- to 5-year Target Price Range.

*Arthur H. Medalie*

Composite Statistics: Electric Utility Industry

| 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|
| 289.2 | 299.3 | 336.7 | 354.1 | ***355*** | ***375*** | Revenues ($bill) | ***440*** |
| 19.3 | 20.3 | 24.0 | 25.7 | ***27.5*** | ***29.5*** | Net Profit ($bill) | ***36.0*** |
| 30.3% | 30.3% | 29.5% | 29.7% | ***33.5%*** | ***34.5%*** | Income Tax Rate | ***34.5%*** |
| 4.3% | 3.5% | 3.5% | 3.3% | ***6.0%*** | ***7.0%*** | AFUDC % to Net Profit | ***4.0%*** |
| 59.1% | 57.2% | 55.7% | 55.0% | ***51.0%*** | ***51.0%*** | Long-Term Debt Ratio | ***49.0%*** |
| 39.2% | 41.7% | 43.1% | 43.9% | ***48.0%*** | ***48.0%*** | Common Equity Ratio | ***50.0%*** |
| 439.5 | 441.8 | 446.1 | 473.9 | ***465*** | ***490*** | Total Capital ($bill) | ***565*** |
| 443.9 | 453.6 | 469.3 | 496.6 | ***490*** | ***520*** | Net Plant ($bill) | ***570*** |
| 6.4% | 6.5% | 7.2% | 7.3% | ***7.0%*** | ***7.0%*** | Return on Total Cap'l | ***7.5%*** |
| 10.7% | 10.8% | 12.1% | 12.2% | ***11.0%*** | ***11.0%*** | Return on Shr. Equity | ***11.5%*** |
| 10.9% | 10.9% | 12.3% | 12.4% | ***11.5%*** | ***11.5%*** | Return on Com Equity | ***11.5%*** |
| 4.8% | 4.7% | 5.5% | 5.5% | ***5.0%*** | ***5.0%*** | Retained to Com Eq | ***5.0%*** |
| 57% | 57% | 56% | 56% | ***60%*** | ***60%*** | All Div'ds to Net Prof | ***60%*** |
| 15.2 | 16.0 | 15.8 | 15.9 | *Bold figures are Value Line estimates* | | Avg Ann'l P/E Ratio | ***14.5*** |
| .80 | .85 | .85 | .83 | | | Relative P/E Ratio | ***.95*** |
| 3.7% | 3.5% | 3.5% | 3.4% | | | Avg Ann'l Div'd Yield | ***3.9%*** |



**All of the major utilities in the eastern region of the United States are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western companies are covered in Issue 11.**

**The Electric Utilities (East) have given investors reason to smile, having registered strong share-price performance in the three months since our last review. Led by *Constellation Energy* (up 19%), gainers outnumbered losers 19 to 2. Strong earnings, driven by the Baltimore utility's nonregulated power operations (generation, marketing), has not gone unnoticed by investors. *Central Vermont Public Service*, meanwhile, was the laggard of the group (down 22%).**

## Safe Haven

With recent interest rate cuts, investors have bid up utility stocks, driving down risk-adjusted yield premiums in the process. Recent volatility in the stock market likely also has given the group a lift, as investors seek out "safe havens". That said, a majority of these stocks are now trading within our three- to five-year Target Price Ranges. This suggests that future returns will mainly come from dividends.

## Good Yields

Conservative income-oriented investors may find what they're looking for in the Electric Utility (East) group. The group's median dividend yield, at 3.8%, is double that of the *Value Line* Composite Index. What's more, a good majority of the stocks rank in the top decile for Price Stability. Allentown, Pennsylvania-based *PPL Corporation* is an interesting, and perhaps not so obvious, investment play here. The stock is currently trading at a relative pricey 18 times earnings and the dividend yield is a fairly modest 2.7%. Still, median total return potential out to 2010-2012 ranks among the highest within the group. In Pennsylvania, *PPL* will make a transition to higher market-based electricity rates, beginning in 2010. The change should really boost *PPL's* earnings and give it the financial wherewithal to aggressively increase its dividend payout. Indeed, we're looking for the annual payout to reach $2.20 a share over the 2010-2012 horizon. That's 80% higher than the current annualized rate.

Investors that are more inclined towards instant

**INDUSTRY TIMELINESS: 69 (of 98)**

gratification may want to check out *Progress Energy*. The North Carolina-based utility sports the group's fattest payout (yield: 5.2%). That said, income-distribution increases are likely to be fairly modest over the next three to five years.

## A Downer

*Central Vermont Public Service* has the ignominious distinction as the group's weakest performer. Shares of the Green Mountain state's largest power company have sold off 22% since our last review. Comparatively, the benchmark S&P 500 Index is relatively unchanged. *CVPS* is small (market capitalization: $300 million) and has relatively few shares outstanding. Recent selling by *CVPS's* largest investor, Charleston industrialist Jerry Zucker, has pressured shares and quieted takeover speculation.

## Odds and Ends

Investors should increasingly pay attention to the fuels that utilities use to generate power. Looming regulations governing the emission of greenhouse gases suggest that utilities with clean carbon profiles will be competitively advantaged. Access to low-cost fuels, meanwhile, is more dear these days, given, for example, the high price of crude oil. That said, high fuel and pollution control costs are often recoverable, typically via rate hikes.

## Investment Advice

Among the positive attributes that investors should look for when seeking an attractive utility are an economically healthy local service territory (such as those in the Southeast); a large customer base; good management-regulator relations; access to low-cost power generation (coal, nuclear); and ample fixed-charge coverage. As always, we recommend that investors read each report carefully before making any decisions.

*Nils C. Van Liew*

**Composite Statistics: Electric Utility Industry**

| 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|
| 277.0 | 288.9 | 325.1 | 336.0 | ***355*** | ***375*** | Revenues ($bill) | ***440*** |
| 18.5 | 20.2 | 22.2 | 25.0 | ***27.5*** | ***29.5*** | Net Profit ($bill) | ***36.0*** |
| 30.4% | 30.4% | 29.6% | 31.9% | ***33.5%*** | ***34.5%*** | Income Tax Rate | ***34.5%*** |
| 4.5% | 3.6% | 3.8% | 4.5% | ***6.0%*** | ***7.0%*** | AFUDC % to Net Profit | ***4.0%*** |
| 58.7% | 56.0% | 54.6% | 52.6% | ***51.0%*** | ***51.0%*** | Long-Term Debt Ratio | ***49.0%*** |
| 39.7% | 42.8% | 44.2% | 46.3% | ***48.0%*** | ***48.0%*** | Common Equity Ratio | ***50.0%*** |
| 418.1 | 426.8 | 432.3 | 447.7 | ***465*** | ***490*** | Total Capital ($bill) | ***565*** |
| 421.3 | 435.2 | 450.3 | 475.0 | ***490*** | ***520*** | Net Plant ($bill) | ***570*** |
| 6.4% | 6.6% | 6.9% | 7.3% | ***7.0%*** | ***7.0%*** | Return on Total Cap'l | ***7.5%*** |
| 10.7% | 10.7% | 11.3% | 11.8% | ***11.0%*** | ***11.0%*** | Return on Shr. Equity | ***11.5%*** |
| 10.8% | 10.9% | 11.5% | 11.9% | ***11.5%*** | ***11.5%*** | Return on Com Equity | ***11.5%*** |
| 4.7% | 4.8% | 4.9% | 5.5% | ***5.0%*** | ***5.0%*** | Retained to Com Eq | ***5.0%*** |
| 58% | 57% | 58% | 55% | ***60%*** | ***60%*** | All Div'ds to Net Prof | ***60%*** |
| 13.7 | 14.8 | 16.3 | 15.7 | | | Avg Ann'l P/E Ratio | ***14.5*** |
| .78 | .78 | .87 | .85 | ***Bold figures are*** | ***Value Line estimates*** | Relative P/E Ratio | ***.95*** |
| 4.2% | 3.8% | 3.5% | 3.4% | | | Avg Ann'l Div'd Yield | ***3.9%*** |

**COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (kwh) | +.3 | +5.4 | +1.3 |
| Average Indust. Use (mwh) | 1384 | 1568 | 1570 |
| Avg. Indust. Revs. per kwh (¢) | 5.25 | 5.73 | 6.17 |
| Regulated Cap. at Peak (mw) | NA | NA | NA |
| Peak Load, Summer (mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr.-end) | +1.6 | +1.2 | +1.7 |
| Fixed Charge Coverage (%) | 230 | 260 | 281 |

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

# ALLETE NYSE-ALE

RECENT PRICE **39.64** | P/E RATIO **15.4** (Trailing: 12.7 Median: NMF) | RELATIVE P/E RATIO **0.91** | DIV'D YLD **4.2%** | **VALUE LINE**

| | | |
|---|---|---|
| TIMELINESS | 3 | Lowered 11/9/07 |
| SAFETY | 2 | New 10/1/04 |
| TECHNICAL | 3 | Raised 12/7/07 |

BETA .95 (1.00 = Market)

| | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|
| High: | 37.5 | 51.7 | 49.3 | 51.3 |
| Low: | 30.8 | 35.7 | 42.6 | 38.2 |

Target Price Range 2010 | 2011 | 2012

**2010-12 PROJECTIONS**

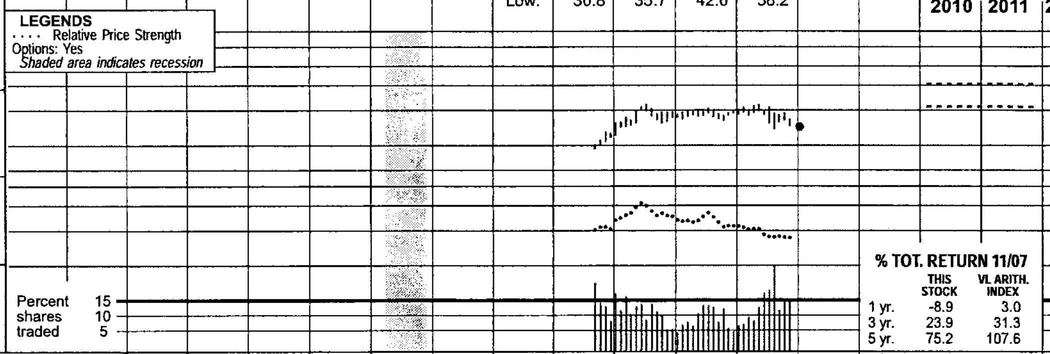
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 65 | (+65%) | 16% |
| Low | 50 | (+25%) | 9% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 |
| Options | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 95 | 71 | 80 |
| to Sell | 51 | 81 | 71 |
| Hld's(000) | 19655 | 19222 | 19001 |




**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -8.9 | 3.0 |
| 3 yr. | 23.9 | 31.3 |
| 5 yr. | 75.2 | 107.6 |

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | -- | -- | -- | -- | -- | -- | 25.30 | 24.50 | 25.23 | *26.60* | *26.70* | Revenues per sh | *29.00* |
| -- | -- | -- | -- | -- | -- | -- | 2.97 | 3.85 | 4.14 | *4.40* | *4.20* | "Cash Flow" per sh | *5.50* |
| -- | -- | -- | -- | -- | -- | -- | 1.35 | 2.48 | 2.77 | *3.00* | *2.70* | Earnings per sh A | *3.50* |
| -- | -- | -- | -- | -- | -- | -- | .30 | 1.25 | 1.45 | *1.64* | *1.68* | Div'd Decl'd per sh B ■ † | *1.80* |
| -- | -- | -- | -- | -- | -- | -- | 2.12 | 1.95 | 3.37 | *5.80* | *8.80* | Cap'l Spending per sh | *5.50* |
| -- | -- | -- | -- | -- | -- | -- | 21.23 | 20.03 | 21.90 | *23.35* | *24.40* | Book Value per sh C | *28.75* |
| -- | -- | -- | -- | -- | -- | -- | 29.70 | 30.10 | 30.40 | *30.85* | *31.30* | Common Shs Outst'g D | *32.50* |
| -- | -- | -- | -- | -- | -- | -- | 25.2 | 17.9 | 16.5 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.0* |
| -- | -- | -- | -- | -- | -- | -- | 1.33 | .95 | .90 | *Value Line* | | Relative P/E Ratio | *1.05* |
| -- | -- | -- | -- | -- | -- | -- | .9% | 2.8% | 3.2% | *estimates* | | Avg Ann'l Div'd Yield | *3.2%* |
| -- | -- | -- | -- | -- | -- | -- | 751.4 | 737.4 | 767.1 | *820* | *835* | Revenues ($mill) | *945* |
| -- | -- | -- | -- | -- | -- | -- | 38.5 | 68.0 | 77.3 | *85.0* | *75.0* | Net Profit ($mill) | *100* |
| -- | -- | -- | -- | -- | -- | -- | 38.8% | 28.4% | 37.5% | *34.5%* | *38.5%* | Income Tax Rate | *38.5%* |
| -- | -- | -- | -- | -- | -- | -- | 1.8% | .4% | .8% | *4.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| -- | -- | -- | -- | -- | -- | -- | 38.2% | 39.1% | 35.1% | *39.5%* | *45.0%* | Long-Term Debt Ratio | *45.5%* |
| -- | -- | -- | -- | -- | -- | -- | 61.8% | 60.9% | 64.9% | *60.5%* | *55.0%* | Common Equity Ratio | *54.5%* |
| -- | -- | -- | -- | -- | -- | -- | 1020.7 | 990.6 | 1025.6 | *1190* | *1385* | Total Capital ($mill) | *1700* |
| -- | -- | -- | -- | -- | -- | -- | 883.1 | 860.4 | 921.6 | *1050* | *1275* | Net Plant ($mill) | *1725* |
| -- | -- | -- | -- | -- | -- | -- | 5.1% | 8.0% | 8.6% | *8.0%* | *6.5%* | Return on Total Cap'l | *7.0%* |
| -- | -- | -- | -- | -- | -- | -- | 6.1% | 11.3% | 11.6% | *11.5%* | *10.0%* | Return on Shr. Equity | *10.5%* |
| -- | -- | -- | -- | -- | -- | -- | 6.1% | 11.3% | 11.6% | *11.5%* | *10.0%* | Return on Com Equity E | *10.5%* |
| -- | -- | -- | -- | -- | -- | -- | 4.7% | 5.2% | 5.0% | *4.5%* | *3.0%* | Retained to Com Eq | *4.5%* |
| -- | -- | -- | -- | -- | -- | -- | 23% | 54% | 57% | *60%* | *68%* | All Div'ds to Net Prof | *58%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $438.4 mill. **Due in 5 Yrs** $143.0 mill.
**LT Debt** $409.0 mill. **LT Interest** $22.3 mill.
(LT interest earned: 7.3x)
**Leases, Uncapitalized** Annual rentals $8.2 mill.

**Pension Assets-12/06** $364.7 mill. **Oblig.** $417.7 mill.

**Pfd Stock** None

**Common Stock** 30,821,767 shs.

**MARKET CAP: $1.2 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +4.9 | +2.0 | +1.1 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 4.03 | 3.93 | 4.15 |
| Capacity at Peak (Mw) | 1511 | 1512 | 1761 |
| Peak Load, Winter (Mw) | 1498 | 1543 | 1586 |
| Annual Load Factor (%) | 80.0 | 80.0 | 80.0 |
| % Change Customers (avg.) | +1.3 | +1.1 | +1.3 |
| Fixed Charge Cov. (%) | 307 | 461 | 503 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | -- | -- | 2.5% |
| "Cash Flow" | -- | -- | 7.0% |
| Earnings | -- | -- | 8.0% |
| Dividends | -- | -- | NMF |
| Book Value | -- | -- | 5.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 209.0 | 186.2 | 177.6 | 178.6 | 751.4 |
| 2005 | 193.3 | 174.4 | 177.4 | 192.3 | 737.4 |
| 2006 | 192.5 | 178.3 | 199.1 | 197.2 | 767.1 |
| 2007 | 205.3 | 223.3 | 200.8 | *190.6* | *820* |
| 2008 | *210* | *205* | *210* | *210* | *835* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .76 | .08 | .36 | .15 | 1.35 |
| 2005 | .64 | .38 | .58 | .88 | 2.48 |
| 2006 | .68 | .49 | .78 | .82 | 2.77 |
| 2007 | .93 | .80 | .58 | *.69* | *3.00* |
| 2008 | *.70* | *.60* | *.70* | *.70* | *2.70* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | -- | -- | -- | -- | -- |
| 2004 | -- | -- | -- | .30 | .30 |
| 2005 | .30 | .315 | .315 | .315 | 1.25 |
| 2006 | .363 | .363 | .363 | .363 | 1.45 |
| 2007 | .41 | .41 | .41 | .41 | |

**BUSINESS:** ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 141,000 customers in northeastern Minn., and Superior Water, Light & Power in northwestern Wisc. Electric revenue mix, '06: taconite mining/processing, 29%; paper/wood products, 11%; other industrial, 7%; residential, 13%; commercial, 14%; wholesale & other, 26%. Has real estate operation in Florida. Discontinued water-utility ops. in '01. Spun off automotive remarketing ops. (ADESA) in '04. Generating sources, '06: coal & lignite, 66%; hydro, 2%; purchased, 32%. '06 deprec. rate: 1.8%. Has 1,500 employees. Chairman, President & CEO: Donald J. Shippar. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

**The difficult market conditions in Florida are hurting ALLETE's real estate operation.** ALLETE owns land there that it adds value to through infrastructure development and enhancements, and then sells to developers. This has been lucrative for the company, and until several months ago, it hadn't felt the effects of the weak market in Florida. Now, however, some sales that were expected to close in 2007 have been delayed or canceled. Accordingly, ALLETE forecasts that its net income from real estate in 2008 will fall short of the $16 million-$18 million it will probably earn in 2007 (compared with $22.8 million in 2006). Thus, **we have slashed our 2008 share-earnings estimate by $0.50**, to $2.70. That's the low end of the company's targeted range of $2.70-$2.90. We have also trimmed our 2007 estimate by $0.05, to the low end of ALLETE's guidance of $3.00-$3.05.

**ALLETE has the wherewithal to ride out the difficult conditions in Florida.** Impairment charges aren't a concern, as the market value of its land is still well above its book value of $59 million as of September 30th. Also, the company's real estate operation has no debt. But it may well take a few years to return to the profit level of 2006.

**The rest of ALLETE's operations are performing well.** Minnesota Power is solid, and is benefiting from strong demand from its largely industrial customer base. The utility is about to file a wholesale rate case with the Federal Energy Regulatory Commission and will file a retail rate case in Minnesota in mid-2008. Minnesota Power also benefits from a regulatory mechanism that enables it to recover environmental capital expenditures through a rate rider, in advance of filing a general rate case. That's important because a $260 million environmental spending program will conclude in 2009. Finally, ALLETE is earning a healthy return of over 11% on its $65 million equity investment in American Transmission Company.

**This stock offers an attractive yield.** In fact, we're estimating a dividend increase in 2008, despite the expected earnings decline. We've lowered our sights for the 2010-2012 period, but total-return potential over that time is still worthwhile.

*Paul E. Debbas, CFA* *December 28, 2007*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢ net; '05, ($1.84); gain (losses) on discontinued operations: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '06: $2.30/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '95: 11.6%; earned on avg. com. eq., '06: 12.1%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | NMF |
| Earnings Predictability | NMF |

# ALLIANT ENERGY NYSE-LNT

| RECENT PRICE | P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD |
|---|---|---|---|
| 41.70 | 16.0 (Trailing: 17.4 Median: 14.0) | 0.95 | 3.5% |

**VALUE LINE**

**TIMELINESS** 4 Lowered 11/10/06

**SAFETY** 2 Raised 9/28/07

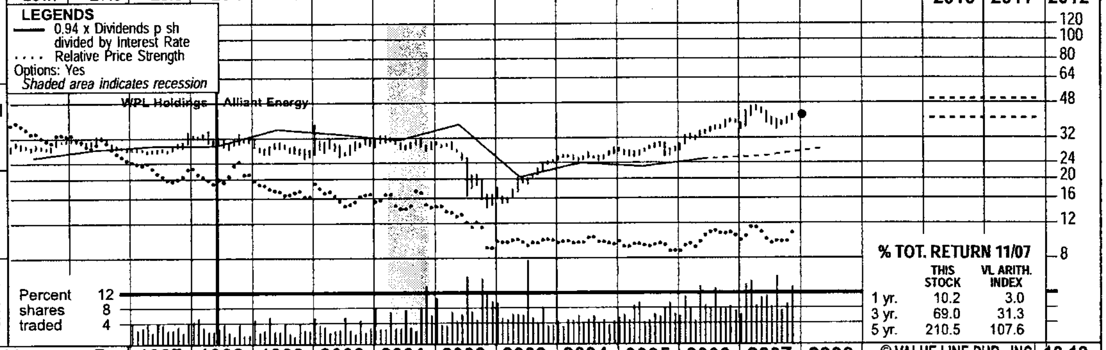
**TECHNICAL** 4 Lowered 12/14/07

**BETA** .80 (1.00 = Market)

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 32.9 | 34.4 | 34.9 | 32.4 | 37.8 | 33.2 | 31.0 | 25.1 | 28.8 | 30.6 | 40.0 | 46.5 |
| Low: | 27.5 | 26.8 | 28.0 | 25.2 | 25.8 | 27.5 | 14.3 | 15.0 | 23.5 | 25.6 | 27.5 | 34.9 |

**Target Price Range** 2010 | 2011 | 2012

LEGENDS
—— 0.94 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+20%) | 8% |
| Low | 40 | (-5%) | 2% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 8 | 1 | 1 | 4 | 2 | 2 | 0 | 0 | 0 |
| to Sell | 7 | 2 | 2 | 4 | 2 | 2 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 135 | 102 | 92 |
| to Sell | 120 | 138 | 146 |
| Hld's(000) | 69556 | 63981 | 62642 |

**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 10.2 | 3.0 |
| 3 yr. | 69.0 | 31.3 |
| 5 yr. | 210.5 | 107.6 |

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share. Data prior to 1998 are for WPL Holdings only and are not comparable with Alliant Energy data.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 29.86 | 27.45 | 27.83 | 30.44 | 30.97 | 28.26 | 28.19 | 25.56 | 28.02 | 28.93 | *32.10* | *33.25* | Revenues per sh | *36.95* |
| 5.60 | 4.85 | 5.71 | 6.57 | 5.82 | 4.52 | 4.19 | 4.69 | 5.46 | 4.33 | *5.35* | *5.60* | "Cash Flow" per sh | *6.65* |
| 1.90 | 1.26 | 2.19 | 2.47 | 2.42 | 1.18 | 1.57 | 1.85 | 2.21 | 2.06 | *2.60* | *2.65* | Earnings per sh A | *2.85* |
| 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 1.00 | 1.02 | 1.05 | 1.15 | *1.27* | *1.40* | Div'd Decl'd per sh B ■ † | *1.70* |
| 4.10 | 4.79 | 6.06 | 13.50 | 9.13 | 7.12 | 7.69 | 5.55 | 4.51 | 3.42 | *5.40* | *10.05* | Cap'l Spending per sh | *4.50* |
| 19.73 | 20.69 | 27.29 | 25.79 | 21.39 | 19.89 | 21.37 | 22.13 | 20.85 | 22.83 | *22.40* | *23.80* | Book Value per sh C | *27.50* |
| 30.79 | 77.63 | 78.98 | 79.01 | 89.68 | 92.30 | 110.96 | 115.74 | 117.04 | 116.13 | *107.20* | *108.00* | Common Shs Outst'g D | *111.00* |
| 15.0 | 25.1 | 13.0 | 11.8 | 12.6 | 19.9 | 12.7 | 14.0 | 12.6 | 16.8 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.0* |
| .86 | 1.31 | .74 | .77 | .65 | 1.09 | .72 | .74 | .67 | .91 | *Value Line* | | Relative P/E Ratio | *1.05* |
| 7.0% | 6.3% | 7.0% | 6.9% | 6.6% | 8.5% | 5.0% | 3.9% | 3.8% | 3.3% | *estimates* | | Avg Ann'l Div'd Yield | *3.8%* |
| 919.3 | 2130.9 | 2198.0 | 2405.0 | 2777.3 | 2608.8 | 3128.2 | 2958.7 | 3279.6 | 3359.4 | *3440* | *3590* | Revenues ($mill) | *4100* |
| 64.6 | 103.4 | 178.2 | 203.1 | 194.9 | 113.1 | 176.6 | 229.5 | 337.8 | 260.1 | *310* | *305* | Net Profit ($mill) | *335* |
| 30.8% | 36.0% | 40.3% | 54.0% | 23.5% | 24.2% | 28.9% | 26.7% | 19.0% | 43.8% | *36.0%* | *36.0%* | Income Tax Rate | *36.0%* |
| 4.3% | 6.6% | 4.1% | 4.3% | 5.7% | 6.8% | 11.7% | 8.1% | 3.0% | 3.1% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| 40.7% | 47.3% | 39.6% | 47.0% | 54.7% | 56.4% | 44.8% | 45.0% | 41.6% | 31.4% | *38.0%* | *40.5%* | Long-Term Debt Ratio | *44.5%* |
| 54.0% | 49.2% | 57.4% | 50.2% | 42.7% | 39.2% | 50.0% | 50.2% | 53.1% | 62.9% | *56.0%* | *54.0%* | Common Equity Ratio | *51.5%* |
| 1125.1 | 3262.9 | 3756.0 | 4061.4 | 4490.2 | 4679.1 | 4738.4 | 5104.7 | 4599.1 | 4218.4 | *4270* | *4740* | Total Capital ($mill) | *5925* |
| 1244.8 | 3101.7 | 3486.0 | 3719.3 | 3862.8 | 3729.2 | 4432.6 | 5284.6 | 4866.2 | 4944.9 | *5240* | *6005* | Net Plant ($mill) | *6345* |
| 7.4% | 4.9% | 6.1% | 6.6% | 6.2% | 4.1% | 5.7% | 6.1% | 8.9% | 7.5% | *9.0%* | *8.0%* | Return on Total Cap'l | *7.5%* |
| 9.7% | 6.0% | 7.9% | 9.4% | 9.6% | 5.5% | 6.8% | 8.2% | 12.6% | 9.0% | *11.5%* | *11.0%* | Return on Shr. Equity | *10.0%* |
| 10.1% | 6.0% | 8.0% | 9.6% | 9.8% | 5.8% | 6.7% | 8.2% | 13.1% | 9.1% | *12.0%* | *11.0%* | Return on Com Equity E | *10.5%* |
| NMF | NMF | .7% | 1.9% | 1.6% | NMF | 2.5% | 3.8% | 8.1% | 4.0% | *6.0%* | *5.0%* | Retained to Com Eq | *4.0%* |
| 100% | NMF | 92% | 81% | 85% | NMF | 67% | 58% | 42% | 59% | *52%* | *56%* | All Div'ds to Net Prof | *62%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $1754.9 mill. **Due in 5 Yrs** $820.0 mill.
**LT Debt** $1593.9 mill. **LT Interest** $136.8 mill.
(LT interest earned: 5.3x)
**Pension Assets-12/06** $738.1 mill. **Oblig.** $866.0 mill.
**Pfd Stock** $243.8 mill. **Pfd Div'd** $18.7 mill.
449,765 shs. $100 par; 8,199,460 shs. $25 par; 1,127,787 shs. $50 par.

**Common Stock** 110,315,565 shs. as of 10/31/07
**MARKET CAP: $4.6 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +.3 | +4.6 | -1.7 |
| Avg. Indust. Use (MWH) | 4320 | 4215 | 4180 |
| Avg. Indust. Revs. per KWH (¢) | 4.84 | 5.26 | 5.96 |
| Capacity at Peak (Mw) | 5737 | 5446 | 4985 |
| Peak Load, Summer (Mw) | 5644 | 5932 | 5987 |
| Annual Load Factor (%) | 48.6 | 55.6 | 52.0 |
| % Change Customers (yr-end) | +1.1 | +1.3 | +1.8 |
| Fixed Charge Cov. (%) | 235 | 252 | 350 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | -- | -1.5% | 5.0% |
| "Cash Flow" | -.5% | -4.5% | 5.5% |
| Earnings | -1.0% | -3.0% | 5.5% |
| Dividends | -6.0% | -11.5% | 8.0% |
| Book Value | 1.0% | -2.5% | 4.0% |

**QUARTERLY REVENUES ($ mill.)**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 891.0 | 662.1 | 730.7 | 674.9 | 2958.7 |
| 2005 | 825.2 | 686.7 | 860.9 | 906.8 | 3279.6 |
| 2006 | 930.9 | 696.8 | 890.4 | 841.3 | 3359.4 |
| 2007 | 912.7 | 746.2 | 907.3 | *873.8* | *3440* |
| 2008 | *950* | *760* | *960* | *920* | *3590* |

**EARNINGS PER SHARE A**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .33 | .30 | .76 | .46 | 1.85 |
| 2005 | .23 | .41 | 1.05 | .52 | 2.21 |
| 2006 | .56 | .39 | .75 | .36 | 2.06 |
| 2007 | .56 | .43 | 1.05 | *.56* | *2.60* |
| 2008 | *.55* | *.45* | *1.05* | *.60* | *2.65* |

**QUARTERLY DIVIDENDS PAID B ■ †**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .25 | .25 | .25 | .263 | 1.01 |
| 2005 | .263 | .263 | .263 | .263 | 1.05 |
| 2006 | .288 | .288 | .288 | .288 | 1.15 |
| 2007 | .318 | .318 | .318 | .318 | |
| 2008 | .35 | | | | |

**BUSINESS:** Alliant Energy, formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies elect. (73% of revs.), gas (19%), and other services (8%) in Wisconsin, Iowa, Minnesota, & Illinois. Elect. revs. by state: WI, 47%; IA, 48%; MN, 3%; IL, 2%. Elect. rev.: resid., 35%; comm'l, 23%; ind'l, 31%; wholesale, 6%; other, 5%. Fuel sources, '06: coal & gas, 57%; nuclear, 1%; purch., 42%. Fuel costs: 54% of revs. '06 deprec. rate: 2.8%. Est'd plant age: 10 yrs. Has 5,151 empls., Chrmn.: Erroll B. Davis, Jr. Pres. & CEO: William D. Harvey. Inc.: WI. Address: 4902 N. Biltmore Lane, P.O. Box 77007, Madison, WI 53707-1007. Tel.: 608-458-3391. Internet: www.alliant-energy.com.

**Alliant Energy has an agreement to sell its remaining transmission assets.** The sale includes 6,800 miles of transmission lines in Iowa, Minnesota, and Illinois; substation facilities; and related transmission land rights. ITC Midwest will pay $750 million in cash for the package, subject to various adjustments at closing. LNT was anxious to finalize the arrangement by yearend in order to capitalize on a provision in the Energy Policy Act of 2005 that allows a utility eight years to pay the tax on capital gains resulting from transmission sales consummated by December 31, 2007. As we go to press, all necessary commission approvals have been received. The transaction will now close before yearend. Since any aftertax gain will be subject to regulatory determination of amounts paid to customers, it isn't clear what impact the sale will have on operations.

**The company is taking steps to cover generating needs.** Demand for power in LNT's service territory is rising by 100 megawatts (mw) annually. To meet short-term obligations, it paid $180 million for the rights to Cedar Ridge's 68-mw wind farm, which is targeted to go on line in late 2008, and it plans to invest up to another $260 million in wind-driven power by the end of 2010. For the longer haul, it asked regulators for approval to build a 300-mw coal-fired station at the existing Nelson Dewey site. This location is desirable because it has ready access to rail and barge transportation, and would permit a 625-mw increase in import capability into Wisconsin. The facility is expected to begin operation in 2012.

**Earnings should move sharply higher in 2007.** Pluses include higher electric rates in Wisconsin, the repurchase of 10 million common shares, and profits from new plants on line. Despite a heavy storm in March that increased operating costs and raised interest expense, we estimate 2007 earnings will rise 26%, to $2.60 a share. A lesser gain is likely next year. For now, the stock is untimely.

**We have a neutral long-term stance on these shares.** Though the yield is a cut below the utility average, dividend growth prospects to 2010-2012 are above those of the group. Moreover, total return prospects mirror the industry average.

*Arthur H. Medalie* *December 28, 2007*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '96, net 7¢; '99, 32¢; '00, $2.56; '01, (28¢); '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 84¢. Next egs. rpt. due late Jan. (B) Div'ds historically paid in mid-Feb., mid-May, mid-Aug., and mid-Nov. ■ Div'd reinvest. plan avail. † shareholder invest. plan avail. (C) Incl. deferred chgs. in '06: $228.8 mill., $1.96/sh. (D) In mill. (E) Rate base: Orig. cost. Rate allowed on com. eq.: in '05, WI, 10.8%; in '07, IA., 10.7%; earned on avg. com. eq., '06: 9.5%. Regul. Clim.: WI, Above Avg.; IA, Below Avg.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 65 |

# AMEREN NYSE-AEE

| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD |
|---|---|---|---|---|
| 53.80 | 16.7 | (Trailing: 19.5 / Median: 15.0) | 0.99 | 4.7% |

VALUE LINE

TIMELINESS 3 Raised 8/24/07

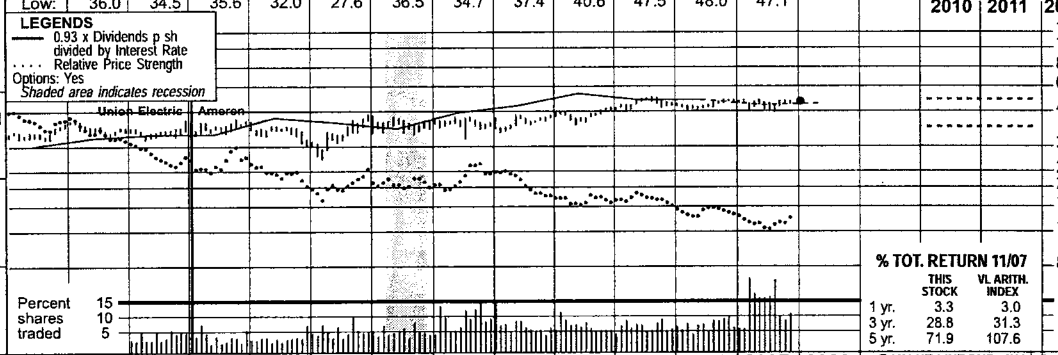
SAFETY 2 Lowered 3/30/07

TECHNICAL 3 Lowered 11/2/07

BETA .80 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 44.1 | 43.8 | 44.3 | 42.9 | 46.9 | 46.0 | 45.3 | 46.5 | 50.4 | 56.8 | 55.2 | 55.0 |
| Low: | 36.0 | 34.5 | 35.6 | 32.0 | 27.6 | 36.5 | 34.7 | 37.4 | 40.6 | 47.5 | 48.0 | 47.1 |

Target Price Range 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 55 | (Nil) | 5% |
| Low | 40 | (-25%) | -2% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 168 | 153 | 136 |
| to Sell | 166 | 161 | 173 |
| Hld's(000) | 125194 | 128902 | 135064 |

**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 3.3 | 3.0 |
| 3 yr. | 28.8 | 31.3 |
| 5 yr. | 71.9 | 107.6 |

Ameren was formed on December 31, 1997 through the merger of Union Electric and CIPSCO. Each common share of Union Electric was exchanged for 1.00 share of Ameren, while each common share of CIPSCO was exchanged for 1.03 Ameren shares. Premerger data are for Union Electric only and are not comparable to Ameren data.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24.24 | 24.18 | 25.68 | 28.10 | 32.64 | 24.93 | 28.20 | 26.43 | 33.12 | 33.30 | *36.00* | *37.35* | Revenues per sh | *41.30* |
| 4.96 | 5.36 | 5.36 | 6.11 | 6.33 | 5.28 | 6.29 | 5.57 | 6.10 | 5.79 | *6.85* | *7.15* | "Cash Flow" per sh | *8.00* |
| 2.44 | 2.82 | 2.81 | 3.33 | 3.41 | 2.66 | 3.14 | 2.82 | 3.13 | 2.66 | *3.25* | *3.30* | Earnings per sh A | *3.40* |
| 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | *2.54* | *2.54* | Div'd Decl'd per sh B■ | *2.54* |
| 2.77 | 2.37 | 4.16 | 6.77 | 7.99 | 5.11 | 4.19 | 4.13 | 4.63 | 4.80 | *6.25* | *7.10* | Cap'l Spending per sh | *6.90* |
| 22.00 | 22.27 | 22.52 | 23.30 | 24.26 | 24.93 | 26.73 | 29.71 | 31.09 | 31.86 | *32.70* | *33.60* | Book Value per sh C | *36.50* |
| 137.22 | 137.22 | 137.22 | 137.22 | 138.05 | 154.10 | 162.90 | 195.20 | 204.70 | 206.60 | *208.80* | *210.80* | Common Shs Outst'g E | *216.80* |
| 15.5 | 14.2 | 13.5 | 11.0 | 12.1 | 15.8 | 13.5 | 16.3 | 16.7 | 19.4 | *Bold figures are* | *Value Line* | Avg Ann'l P/E Ratio | *14.0* |
| .89 | .74 | .77 | .72 | .62 | .86 | .77 | .86 | .89 | 1.05 | *estimates* | | Relative P/E Ratio | *.95* |
| 6.7% | 6.3% | 6.7% | 6.9% | 6.2% | 6.1% | 6.0% | 5.5% | 4.9% | 4.9% | | | Avg Ann'l Div'd Yield | *5.4%* |
| 3326.5 | 3318.2 | 3523.6 | 3855.8 | 4505.9 | 3841.0 | 4593.0 | 5160.0 | 6780.0 | 6880.0 | *7520* | *7870* | Revenues ($mill) | *8950* |
| 347.3 | 399.1 | 397.8 | 469.8 | 481.0 | 393.0 | 517.0 | 541.0 | 628.0 | 547.0 | *685* | *705* | Net Profit ($mill) | *750* |
| 40.3% | 40.1% | 39.4% | 39.1% | 38.4% | 38.9% | 36.8% | 34.3% | 35.6% | 35.8% | *36.0%* | *36.0%* | Income Tax Rate | *36.0%* |
| 3.7% | 3.0% | 3.6% | 2.9% | 4.3% | 2.8% | 1.9% | 1.8% | 2.9% | .7% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| 43.5% | 41.0% | 42.4% | 44.4% | 44.2% | 46.0% | 47.3% | 45.5% | 44.9% | 43.8% | *44.5%* | *44.5%* | Long-Term Debt Ratio | *45.5%* |
| 52.4% | 54.8% | 53.5% | 51.8% | 52.2% | 51.4% | 50.6% | 52.6% | 53.3% | 54.6% | *54.0%* | *53.5%* | Common Equity Ratio | *53.0%* |
| 5760.2 | 5580.7 | 5773.4 | 6176.9 | 6419.3 | 7468.0 | 8606.0 | 11036 | 11932 | 12063 | *12645* | *13300* | Total Capital ($mill) | *14925* |
| 6987.1 | 6928.0 | 7165.2 | 7705.7 | 8426.6 | 8914.0 | 10917 | 13297 | 13572 | 14286 | *14825* | *15505* | Net Plant ($mill) | *17185* |
| 7.5% | 8.7% | 8.2% | 8.9% | 8.7% | 6.5% | 7.4% | 6.0% | 6.5% | 5.7% | *6.5%* | *6.5%* | Return on Total Cap'l | *6.5%* |
| 10.7% | 12.1% | 12.0% | 13.7% | 13.4% | 9.7% | 11.4% | 9.0% | 9.5% | 8.1% | *9.5%* | *9.5%* | Return on Shr. Equity | *9.5%* |
| 11.1% | 12.6% | 12.5% | 14.3% | 14.0% | 9.9% | 11.6% | 9.1% | 9.7% | 8.1% | *10.0%* | *10.0%* | Return on Com Equity D | *9.0%* |
| .1% | 1.2% | 1.2% | 3.4% | 3.6% | .2% | 2.2% | .9% | 1.7% | .2% | *2.0%* | *2.0%* | Retained to Com Eq | *2.5%* |
| 99% | 90% | 91% | 77% | 75% | 98% | 81% | 91% | 83% | 97% | *79%* | *77%* | All Div'ds to Net Prof | *75%* |

**CAPITAL STRUCTURE as of 9/30/07**

**Total Debt** $6891.0 mill. **Due in 5 Yrs** $2395.0 mill.
**LT Debt** $5486.0 mill. **LT Interest** $288.7 mill.

(LT interest earned: 4.0x)

**Pension Assets-12/06** $2.61 bill. **Oblig.** $3.12 bill.

**Pfd Stock** $211.0 mill. **Pfd Div'd** $11.0 mill.
1,137,595 shs. $3.50 to $7.64 cum. (no par), stated at liquid. value; 191,204 shs., $100 par, 4.50% to to 4.60%; 800,000 shs. 4.00% to 6.625%.

**Common Stock** 206,000,000 shs.

**MARKET CAP: $11.1 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +7.4 | +15.0 | +4.5 |
| Avg. Indust. Use (MWH) | 3108 | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 4.05 | 4.27 | 4.25 |
| Capacity at Peak (Mw) | 19439 | 20888 | 21177 |
| Peak Load, Summer (Mw) | 15991 | 17563 | 16416 |
| Annual Load Factor (%) | 58.2 | NA | NA |
| % Change Customers (yr-end) | +19.4 | NA | NA |
| Fixed Charge Cov. (%) | 356 | 377 | 294 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 4.0% | 1.5% | *5.0%* |
| "Cash Flow" | 1.5% | -.5% | *5.5%* |
| Earnings | -- | -2.0% | *3.0%* |
| Dividends | .5% | -- | *Nil* |
| Book Value | 3.0% | 5.5% | *3.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 1216 | 1152 | 1317 | 1475 | 5160.0 |
| 2005 | 1621 | 1590 | 1868 | 1701 | 6780.0 |
| 2006 | 1800 | 1550 | 1910 | 1620 | 6880.0 |
| 2007 | 2019 | 1723 | 1997 | *1781* | *7520* |
| 2008 | *2095* | *1790* | *2095* | *1890* | *7870* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .55 | .65 | 1.20 | .42 | 2.82 |
| 2005 | .62 | .93 | 1.37 | .21 | 3.13 |
| 2006 | .34 | .60 | 1.42 | .30 | 2.66 |
| 2007 | .68 | .69 | 1.36 | *.52* | *3.25* |
| 2008 | *.65* | *.70* | *1.50* | *.45* | *3.30* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .635 | .635 | .635 | .635 | 2.54 |
| 2004 | .635 | .635 | .635 | .635 | 2.54 |
| 2005 | .635 | .635 | .635 | .635 | 2.54 |
| 2006 | .635 | .635 | .635 | .635 | 2.54 |
| 2007 | .635 | .635 | .635 | .635 | |

**BUSINESS:** Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 2003; Illinois Power 2004. Supplies elect. and gas to 3,400,000 customers in Missouri (40% elect. revs.) and Illinois (60%). Elect. revs.: resid., 31%; commer., 29%; indust., 18%; other, 22%. Largest indust. customers: primary metals, chemicals, transportation equipment, petroleum refining. 2006 fuels: coal, 85%; nuclear, 13%; other, 2%. Fuel costs, 45% of revenues; labor costs, 12%. 2006 depreciation rate: 3%-4%. Estimated plant age: 13 years. Has 8,988 employees. Chrmn., CEO, and Pres.: Gary L. Rainwater. Inc.: Missouri. Address: 1901 Chouteau Street, St. Louis, Missouri 63166. Telephone: 314-621-3222. Internet: www.ameren.com.

**Ameren has filed for higher rates in Illinois.** Last month, AEE's three utility subsidiaries in the state applied for increases totaling $180 million in electric transmission and distribution rates and $67 million in higher posted natural gas tariffs. The boosts would allow recovery of infrastructure investments and would permit recoupment of plans to spend $900 million to improve system reliability through 2010. Management maintains that the January, 2007 increase, from which $150 million will be returned to customers over four years, is inadequate to provide service and earn a reasonable return. Stiff resistance to the request is likely from consumer groups and state legislators. Whatever amount the commission approves will take effect in October, 2008.

**In Missouri, the company plans capital outlays of $1 billion over three years to enhance performance.** The increase includes expenditures of $300 million to protect the system against severe weather by placing transmission cables most at risk underground. Another $145 million will be spent on tree trimming to lessen the impact of ice storms that have been the cause of heavy damage. Finally, to comply with U.S. Environmental Protection Agency rules, AEE will spend $500 million to reduce pollution emissions. Since cash flow from operations won't cover these costs, long-term debt offerings will be necessary to bridge the gap.

**Earnings should improve this year.** Pluses include higher rates in two jurisdictions and wider electric margins on replacement of below-market contracts. Though costs related to last January's ice storm pared earnings by $0.09 a share, and refueling of the Callaway 1 nuclear plant will require additional power purchases, we estimate 2007 earnings will rise 22%, to $3.25 a share. Emphasis on core operations suggests slow, but steady, gains through 2010-2012.

**The stock offers an even balance of positives and negatives.** The probable absence of a dividend hike in our 3- to 5-year horizon is offset by an above-average yield. Though total return prospects are unexciting, those investors of a conservative bent might be satisfied because of Ameren's strong finances.

*Arthur H. Medalie* *December 28, 2007*

(A) EPS basic. Excl. nonrecur. gain, (loss): '03, 11¢; '05, (11¢). Next egs. report due late Jan. (B) Div'ds historically paid in late March, late June, late Sept., and late Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred chgs. in '06, $11.99/sh. (D) Rate base: orig. cost depreciated. Rate allowed in MO on common equity in '97: 10.25%; earned on average com. eq. in '06: 8.5%. Regul. Clim.: Average. (E) In millions.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 80 |

# AMERICAN ELEC. PWR. NYSE-AEP

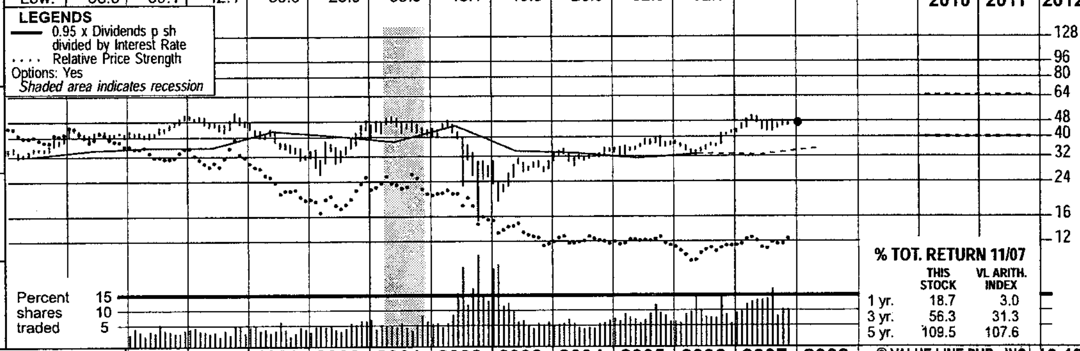
| RECENT PRICE | P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD |
|---|---|---|---|
| 47.14 | 16.4 (Trailing: 16.9; Median: 13.0) | 0.97 | 3.5% |

**VALUE LINE**

TIMELINESS 3 Lowered 6/8/07
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Raised 12/14/07
BETA .95 (1.00 = Market)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 44.8 | 52.0 | 53.3 | 48.2 | 48.9 | 51.2 | 48.8 | 31.5 | 35.5 | 40.8 | 43.1 | 51.2 |
| Low: | 38.6 | 39.1 | 42.1 | 30.6 | 25.9 | 39.3 | 15.1 | 19.0 | 28.5 | 32.3 | 32.3 | 41.7 |

Target Price Range 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 65 | (+40%) | 12% |
| Low | 40 | (-15%) | 1% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 1 | 0 | 6 | 1 | 0 | 1 | 0 | 2 |
| to Sell | 0 | 1 | 0 | 7 | 0 | 0 | 1 | 0 | 2 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 226 | 205 | 206 |
| to Sell | 222 | 230 | 199 |
| Hld's(000) | 286566 | 282116 | 278067 |

**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 18.7 | 3.0 |
| 3 yr. | 56.3 | 31.3 |
| 5 yr. | 109.5 | 107.6 |

American Electric Power acquired Central and South West Corporation (CSW) in 2000. CSW common stockholders received 0.6 of an AEP common share for each of their shares, for a total of $4.5 billion. The transaction was effected under pooling-of-interests accounting rules. The data on this page prior to 2000 do not reflect the addition of CSW.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 32.43 | 33.08 | 35.63 | 42.53 | 190.10 | 42.96 | 36.82 | 35.51 | 30.76 | 31.82 | 33.20 | 34.65 | Revenues per sh | 39.00 |
| 6.47 | 6.03 | 6.36 | 5.11 | 7.65 | 6.99 | 5.76 | 5.89 | 5.96 | 6.54 | 6.55 | 6.90 | "Cash Flow" per sh | 8.25 |
| 3.28 | 2.81 | 2.69 | 1.04 | 3.27 | 2.86 | 2.53 | 2.61 | 2.64 | 2.86 | 2.80 | 3.15 | Earnings per sh A | 4.00 |
| 2.40 | 2.40 | 2.40 | 2.40 | 2.40 | 2.40 | 1.65 | 1.40 | 1.42 | 1.50 | 1.58 | 1.67 | Div'd Decl'd per sh B ■ † | 2.20 |
| 4.00 | 4.13 | 4.47 | 5.51 | 5.69 | 5.08 | 3.44 | 4.28 | 6.11 | 8.89 | 8.90 | 9.40 | Cap'l Spending per sh | 8.25 |
| 24.62 | 25.24 | 25.79 | 25.01 | 25.54 | 20.85 | 19.93 | 21.32 | 23.08 | 23.73 | 24.90 | 26.55 | Book Value per sh C | 32.00 |
| 189.99 | 191.82 | 194.10 | 322.02 | 322.24 | 338.84 | 395.02 | 395.86 | 393.72 | 396.67 | 400.50 | 404.00 | Common Shs Outst'g D | 413.00 |
| 13.4 | 17.0 | 14.3 | NMF | 13.9 | 12.7 | 10.7 | 12.4 | 13.7 | 12.9 | Bold figures are | | Avg Ann'l P/E Ratio | 13.0 |
| .77 | .88 | .82 | NMF | .71 | .69 | .61 | .66 | .73 | .70 | Value Line | | Relative P/E Ratio | .85 |
| 5.5% | 5.0% | 6.2% | 6.7% | 5.3% | 6.6% | 6.1% | 4.3% | 3.9% | 4.1% | estimates | | Avg Ann'l Div'd Yield | 4.2% |
| 6161.4 | 6345.9 | 6916.0 | 13694 | 61257 | 14555 | 14545 | 14057 | 12111 | 12622 | 13300 | 14000 | Revenues ($mill) | 16100 |
| 638.2 | 547.1 | 532.0 | 332.0 | 1063.0 | 976.0 | 984.0 | 1038.0 | 1036.0 | 1131.0 | 1120 | 1275 | Net Profit ($mill) | 1620 |
| 34.8% | 36.6% | 32.8% | 66.1% | 36.0% | 25.2% | 38.8% | 33.1% | 29.3% | 33.0% | 32.5% | 33.0% | Income Tax Rate | 33.0% |
| 1.6% | 1.7% | 1.9% | -- | -- | -- | 3.8% | 3.6% | 5.4% | 9.9% | 11.0% | 12.0% | AFUDC % to Net Profit | 10.0% |
| 51.4% | 57.6% | 55.1% | 52.9% | 54.6% | 56.0% | 60.6% | 56.2% | 54.8% | 56.7% | 58.0% | 59.0% | Long-Term Debt Ratio | 56.5% |
| 46.9% | 41.0% | 43.5% | 44.4% | 44.6% | 43.1% | 38.7% | 43.1% | 44.9% | 43.0% | 42.0% | 40.5% | Common Equity Ratio | 43.0% |
| 9981.0 | 11815 | 11506 | 18151 | 18459 | 16393 | 20333 | 19584 | 20222 | 21902 | 23800 | 26325 | Total Capital ($mill) | 30500 |
| 11633 | 11730 | 13055 | 22393 | 24543 | 21684 | 22029 | 22801 | 24284 | 26781 | 29325 | 31650 | Net Plant ($mill) | 37500 |
| 8.1% | 6.2% | 6.6% | 3.8% | 7.5% | 7.5% | 6.6% | 7.0% | 6.6% | 6.7% | 6.0% | 6.5% | Return on Total Cap'l | 7.0% |
| 13.2% | 10.9% | 10.3% | 3.9% | 12.7% | 13.5% | 12.3% | 12.1% | 11.3% | 11.9% | 11.0% | 12.0% | Return on Shr. Equity | 12.0% |
| 13.3% | 11.1% | 10.4% | 3.7% | 12.8% | 13.7% | 12.4% | 12.2% | 11.3% | 12.0% | 11.0% | 12.0% | Return on Com Equity E | 12.5% |
| 3.6% | 1.6% | 1.1% | NMF | 3.4% | 2.4% | 4.5% | 5.7% | 5.2% | 5.7% | 5.0% | 5.5% | Retained to Com Eq | 5.5% |
| 74% | 86% | 89% | NMF | 74% | 82% | 64% | 54% | 54% | 53% | 57% | 53% | All Div'ds to Net Prof | 56% |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $15363 mill. **Due in 5 Yrs** $4543 mill.
**LT Debt** $13866 mill. **LT Interest** $763 mill.
Incl. $2.26 bill. securitized bonds.
(LT interest earned: 3.1x)

**Leases, Uncapitalized** Annual rentals $331 mill.

**Pension Assets-12/06** $4.35 bill. **Oblig.** $4.11 bill.

**Pfd Stock** $61 mill. **Pfd Div'd** $3 mill.
607,044 shs. 4%-5%, cumulative, callable at $102-$110.
**Common Stock** 400,006,022 shs.
**as of 10/31/07**
**MARKET CAP: $19 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +.7 | +3.7 | -.6 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 3.57 | 3.75 | 4.50 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load (Mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +.6 | +.8 | +1.3 |
| Fixed Charge Cov. (%) | 244 | 258 | 265 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | .5% | -18.0% | 3.0% |
| "Cash Flow" | -- | -1.0% | 5.0% |
| Earnings | -.5% | 3.0% | 6.5% |
| Dividends | -5.0% | -9.5% | 7.5% |
| Book Value | -.5% | -2.5% | 6.0% |

**QUARTERLY REVENUES ($ mill.)**

| Calendar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 3364 | 3408 | 3780 | 3505 | 14057 |
| 2005 | 3065 | 2819 | 3328 | 2899 | 12111 |
| 2006 | 3108 | 2936 | 3594 | 2984 | 12622 |
| 2007 | 3169 | 3146 | 3789 | 3196 | 13300 |
| 2008 | 3400 | 3300 | 4000 | 3300 | 14000 |

**EARNINGS PER SHARE A**

| Calendar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .73 | .38 | .80 | .69 | 2.61 |
| 2005 | .90 | .57 | .95 | .23 | 2.64 |
| 2006 | .96 | .44 | 1.01 | .45 | 2.86 |
| 2007 | .68 | .64 | 1.02 | .46 | 2.80 |
| 2008 | .75 | .65 | 1.20 | .55 | 3.15 |

**QUARTERLY DIVIDENDS PAID B ■ †**

| Calendar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .60 | .35 | .35 | .35 | 1.65 |
| 2004 | .35 | .35 | .35 | .35 | 1.40 |
| 2005 | .35 | .35 | .35 | .37 | 1.42 |
| 2006 | .37 | .37 | .37 | .39 | 1.50 |
| 2007 | .39 | .39 | .39 | .41 | |

**BUSINESS:** American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves about 5.1 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown, '06: residential, 30%; commercial, 22%; industrial, 20%; wholesale, 22%; other, 6%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 37% of revenues. '06 depreciation rate: 3.5%. Has 20,400 employees. Chairman, President & CEO: Michael G. Morris. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

**Capital spending, followed by rate relief, should continue to be the key driver of American Electric Power's earnings growth.** Currently, much of the capital spending is associated with a $5.1 billion environmental program that began in 2004 and will run through 2010. As these expenditures start to wind down, transmission spending will begin ramping up. There will be some spending on generating assets as well—Southwestern Electric is proposing to build a coal-fired plant in Arkansas—plus the usual expenditures on the distribution system to accommodate growth in the utilities' service areas and to maintain system reliability.

**The utilities have received some rate orders in 2007.** Public Service of Oklahoma and Texas Central received rate orders that should boost pretax earnings by $20 million and $50 million, respectively. Appalachian Power was granted an increase of $48.9 million in Virginia for the recovery of environmental and reliability costs. Most of the rate orders have been good, but the Texas commission allowed AEP an ROE of just 9.96% on transmission investment in the state, well below the 11.25% requested.

**Other rate cases are pending.** AEP's utilities in Ohio are seeking a total of $50 million in rate relief to recover some generation-related expenditures. (It's still an open question what will happen to AEP's customers in the state when rate caps expire at the end of 2008.) Appalachian Power is seeking $97 million in Virginia for costs associated with fuel and a proposed generating facility.

**We expect a solid earnings increase in 2008.** Rate relief should be the key factor. Our estimate is at the midpoint of AEP's targeted range of $3.00-$3.30 a share.

**The board of directors has increased the dividend.** The board boosted the quarterly payout by two cents a share (5.1%), to $0.41. We project that solid dividend growth will continue through 2010-2012, but that the disbursement won't return to the level before it was cut in 2003. AEP is targeting a 55%-60% payout ratio.

**We have a neutral stance on this stock.** The yield and 3- to 5-year total-return potential are just average, by utility standards.

*Paul E. Debbas, CFA* *December 28, 2007*

(A) Excl. extra. gain (losses): '01, (26¢); '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); gains (losses) on disc. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢. '04 & '05 EPS don't add due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '06: $14.17/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.96%-15.7%; earned on avg. com. eq., '06: 12.1%. Regulat. Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 10 |
| Earnings Predictability | 65 |

# CH ENERGY GROUP NYSE-CHG

RECENT PRICE 43.64 | P/E RATIO 16.5 (Trailing: 17.0 Median: 15.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.9% | VALUE LINE

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 31.5 | 43.9 | 47.1 | 45.0 | 46.3 | 45.9 | 52.4 | 49.7 | 49.6 | 50.2 | 54.9 | 53.8 | |
| Low: | 28.8 | 29.8 | 38.9 | 30.6 | 26.1 | 38.3 | 39.9 | 40.2 | 43.1 | 42.1 | 44.6 | 41.4 | |

Target Price Range: 2010 | 2011 | 2012

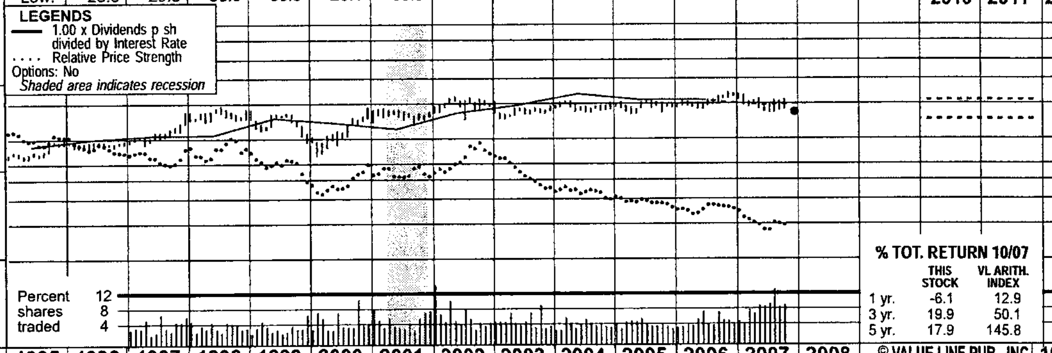
TIMELINESS 3 Raised 10/19/07

SAFETY 1 Raised 12/7/01

TECHNICAL 3 Raised 8/31/07

BETA .90 (1.00 = Market)

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+15%) | 8% |
| Low | 40 | (-10%) | 3% |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 55 | 60 | 56 |
| to Sell | 36 | 39 | 37 |
| Hld's(000) | 7948 | 8347 | 8641 |

Percent shares traded: 12, 8, 4

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -6.1 | 12.9 |
| 3 yr. | 19.9 | 50.1 |
| 5 yr. | 17.9 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31.38 | 32.66 | 30.52 | 29.91 | 29.28 | 29.28 | 30.11 | 29.86 | 30.95 | 45.83 | 44.52 | 43.29 | 51.18 | 50.22 | 61.70 | 63.03 | *72.95* | *80.90* | Revenues per sh | *100.00* |
| 4.99 | 5.22 | 5.23 | 5.25 | 5.33 | 5.69 | 5.80 | 5.83 | 5.92 | 6.49 | 5.50 | 4.18 | 5.02 | 4.89 | 5.11 | 4.83 | *5.10* | *5.40* | "Cash Flow" per sh | *6.25* |
| 2.40 | 2.55 | 2.68 | 2.68 | 2.74 | 2.99 | 2.97 | 2.90 | 2.88 | 3.05 | 3.11 | 2.12 | 2.78 | 2.69 | 2.81 | 2.56 | *2.60* | *2.80* | Earnings per sh A | *3.25* |
| 1.90 | 1.98 | 2.05 | 2.08 | 2.10 | 2.12 | 2.14 | 2.16 | 2.16 | 2.16 | 2.16 | 2.16 | 2.16 | 2.16 | 2.16 | 2.16 | *2.16* | *2.16* | Div'd Decl'd per sh B ■ † | *2.26* |
| 4.44 | 3.81 | 3.13 | 3.37 | 2.87 | 2.84 | 2.54 | 2.71 | 2.76 | 3.58 | 4.14 | 4.50 | 3.79 | 3.98 | 4.05 | 4.76 | *5.70* | *5.40* | Cap'l Spending per sh | *5.25* |
| 22.84 | 23.60 | 24.65 | 25.33 | 25.96 | 26.87 | 27.61 | 28.00 | 28.73 | 29.38 | 30.33 | 30.31 | 30.80 | 31.31 | 31.97 | 32.54 | *33.05* | *33.65* | Book Value per sh C | *35.50* |
| 15.77 | 16.03 | 16.95 | 17.24 | 17.50 | 17.56 | 17.28 | 16.86 | 16.86 | 16.36 | 16.36 | 16.06 | 15.76 | 15.76 | 15.76 | 15.76 | *15.76* | *15.76* | Common Shs Outst'g D | *15.00* |
| 10.7 | 11.2 | 12.2 | 10.0 | 10.2 | 10.1 | 11.5 | 14.6 | 13.5 | 11.4 | 13.6 | 22.6 | 15.7 | 17.2 | 16.5 | 19.1 | *Bold figures are* | *Value Line* | Avg Ann'l P/E Ratio | *14.0* |
| .68 | .68 | .72 | .66 | .68 | .63 | .66 | .76 | .77 | .74 | .70 | 1.23 | .90 | .91 | .88 | 1.03 | *estimates* | | Relative P/E Ratio | *.95* |
| 7.4% | 6.9% | 6.3% | 7.8% | 7.5% | 7.0% | 6.3% | 5.1% | 5.6% | 6.2% | 5.1% | 4.5% | 4.9% | 4.7% | 4.7% | 4.4% | | | Avg Ann'l Div'd Yield | *5.0%* |

**CAPITAL STRUCTURE as of 9/30/07**
Total Debt $439.9 mill. Due in 5 Yrs $77.0 mill.
LT Debt $403.9 mill. LT Interest $18.6 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized Annual rentals $3.1 mill.
Pension Assets-12/06 $359.6 mill. Oblig. $414.5 mill.
Pfd Stock $21.0 mill. Pfd Div'd $1.0 mill.
210,300 shs. 4½%-4.96% cum., $100 par, redeemable at $101-$107/sh.

Common Stock 15,762,000 shs. as of 11/1/07
MARKET CAP: $675 million (Small Cap)

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 520.3 | 503.5 | 521.9 | 749.9 | 728.4 | 695.5 | 806.7 | 791.5 | 972.5 | 993.4 | *1150* | *1275* | Revenues ($mill) | *1500* |
| 55.1 | 52.5 | 51.8 | 54.2 | 54.1 | 36.6 | 45.4 | 43.4 | 45.3 | 41.4 | *42.0* | *45.0* | Net Profit ($mill) | *48.0* |
| 32.3% | 35.3% | 35.8% | 41.4% | -- | 36.6% | 40.1% | 41.9% | 36.3% | 36.3% | *40.0%* | *40.0%* | Income Tax Rate | *40.0%* |
| 1.2% | 1.7% | .8% | 1.4% | 1.4% | 2.3% | 1.6% | .9% | .9% | 1.5% | *1.0%* | *1.0%* | AFUDC % to Net Profit | *1.0%* |
| 40.4% | 40.3% | 38.3% | 37.4% | 28.1% | 34.1% | 35.5% | 38.3% | 39.6% | 38.8% | *42.5%* | *44.5%* | Long-Term Debt Ratio | *50.0%* |
| 53.3% | 53.3% | 55.3% | 56.1% | 64.6% | 61.6% | 61.8% | 59.1% | 58.0% | 58.8% | *55.0%* | *53.5%* | Common Equity Ratio | *48.5%* |
| 895.0 | 885.1 | 875.9 | 857.1 | 768.5 | 790.3 | 785.3 | 834.4 | 868.7 | 871.8 | *945* | *990* | Total Capital ($mill) | *1100* |
| 932.8 | 928.2 | 921.4 | 930.9 | 561.8 | 601.7 | 707.5 | 745.1 | 779.5 | 827.1 | *880* | *925* | Net Plant ($mill) | *1050* |
| 7.4% | 7.2% | 7.3% | 7.7% | 8.1% | 5.4% | 6.5% | 5.9% | 6.0% | 5.7% | *5.5%* | *5.5%* | Return on Total Cap'l | *5.5%* |
| 10.3% | 9.9% | 9.6% | 10.1% | 9.8% | 7.0% | 9.0% | 8.4% | 8.6% | 7.7% | *7.5%* | *8.0%* | Return on Shr. Equity | *8.5%* |
| 10.9% | 10.4% | 10.0% | 10.6% | 10.2% | 7.1% | 9.1% | 8.6% | 8.8% | 7.9% | *8.0%* | *8.5%* | Return on Com Equity E | *9.0%* |
| 3.1% | 2.7% | 2.5% | 3.1% | 3.1% | NMF | 2.0% | 1.7% | 2.0% | 1.2% | *1.5%* | *2.0%* | Retained to Com Eq | *2.5%* |
| 73% | 76% | 77% | 73% | 71% | 102% | 78% | 81% | 77% | 85% | *84%* | *79%* | All Div'ds to Net Prof | *73%* |

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.1 | +4.5 | -4.2 |
| Avg. Indust. Use (MWH) | 1407 | 1407 | 1377 |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | 1051 | 1204 | 1295 |
| Peak Load, Summer (Mw) | 1051 | 1204 | 1295 |
| Annual Load Factor (%) | 61.0 | 57.0 | 50.0 |
| % Change Customers (avg.) | +1.0 | +1.3 | +.9 |
| Fixed Charge Cov. (%) | 374 | 408 | 328 |

**BUSINESS:** CH Energy Group, Inc. is a holding company for Central Hudson Gas & Electric, which provides electricity and gas in the Mid-Hudson Valley region of New York State (79% of '06 income). Customers: 293,000 electric, 71,000 gas. Griffith Energy provides gas, oil, electricity, & propane to over 100,000 customers in Northeast (4% of '06 income). Investments were 17% of '06 income. Electric revenue breakdown, '06: residential, 51%; commercial, 32%; industrial, 7%; other, 10%. Generating sources, '06: hydro, 3%; purchased, 97%. Fuel costs: 66% of revenues. '06 reported depreciation rate (utility): 3.0%. Chairman, President & CEO: Steven V. Lant. Inc.: NY. Address: 284 South Ave., Poughkeepsie, NY 12601-4879. Tel.: 845-452-2000. Internet: www.chenergy.com.

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 7.0% | 7.5% | *9.5%* |
| "Cash Flow" | -1.0% | -3.5% | *4.0%* |
| Earnings | -.5% | -2.5% | *3.0%* |
| Dividends | .5% | -- | *1.0%* |
| Book Value | 2.0% | 1.5% | *2.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 263.0 | 165.3 | 161.9 | 201.3 | 791.5 |
| 2005 | 286.1 | 189.6 | 227.9 | 268.9 | 972.5 |
| 2006 | 317.2 | 213.9 | 239.8 | 222.5 | 993.4 |
| 2007 | 343.4 | 271.0 | 260.1 | *275.5* | *1150* |
| 2008 | *375* | *300* | *300* | *300* | *1275* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 1.46 | .35 | .28 | .60 | 2.69 |
| 2005 | 1.29 | .41 | .36 | .74 | 2.81 |
| 2006 | 1.16 | .26 | .55 | .60 | 2.56 |
| 2007 | 1.37 | .33 | .27 | *.63* | *2.60* |
| 2008 | *1.40* | *.35* | *.35* | *.70* | *2.80* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .54 | .54 | .54 | .54 | 2.16 |
| 2004 | .54 | .54 | .54 | .54 | 2.16 |
| 2005 | .54 | .54 | .54 | .54 | 2.16 |
| 2006 | .54 | .54 | .54 | .54 | 2.16 |
| 2007 | .54 | .54 | .54 | .54 | |

**We have cut our earnings estimates for CH Energy Group.** We had expected third-quarter earnings to decline from the unusually high level of 2006, but the drop was steeper than we had estimated. In addition, Central Hudson Gas and Electric is experiencing decelerating customer growth, which stems from the troubles in the housing market. This has caused electric and gas sales to fall below the levels that were assumed in the utility's last rate order, which was issued in 2006 and is in effect until mid-2009. On the nonutility end, the company's ethanol plant is experiencing a difficult commodities market, although it should be noted that this is a small equity investment, at just $2.7 million. Putting it all together, we have lowered our 2007 share-earnings estimate from $2.70 to $2.60 and have reduced our 2008 forecast from $2.85 to $2.80. The stock is ranked 3 (Average) for Timeliness.

**The company's Griffith Energy subsidiary continues to expand through acquisitions.** This heating oil distributor has spent approximately $16 million on eight acquisitions so far in 2007. There are ample opportunities for expansion, and not just from troubled operators. This is a fragmented industry with a lot of family-owned businesses, and some very successful owners have approached Griffith because they want to cash out as they prepare for retirement.

**Finances are solid.** The common-equity ratio should remain high even though Central Hudson has added some debt to finance its capital spending needs. Also, the fixed-charge coverage is well above the industry average. The company merits a Financial Strength rating of A.

**High-quality CH Energy stock offers an above-average yield,** even by utility standards. This reflects the fact that the dividend hasn't been raised since the late 1990s. Although we project that dividend growth will resume over the 3- to 5-year period, because the stock is already trading well within our 2010-2012 Target Price Range, total-return potential over that time is subpar. CH Energy has been viewed as a takeover candidate for several years, but we do not advise investors to purchase this equity with the hope that a buyout will occur.

*Paul E. Debbas, CFA* *November 30, 2007*

(A) Diluted earnings. Excl. nonrecurring gains: '92, 10¢; '02, 12¢; '06, 17¢; gain from discontinued operation: '02, 29¢. '05 & '06 earnings don't add to total due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '06: $299.2 mill., $18.98/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '06: 10.6%; earned on avg. com. eq., '06: 8.0%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 85 |

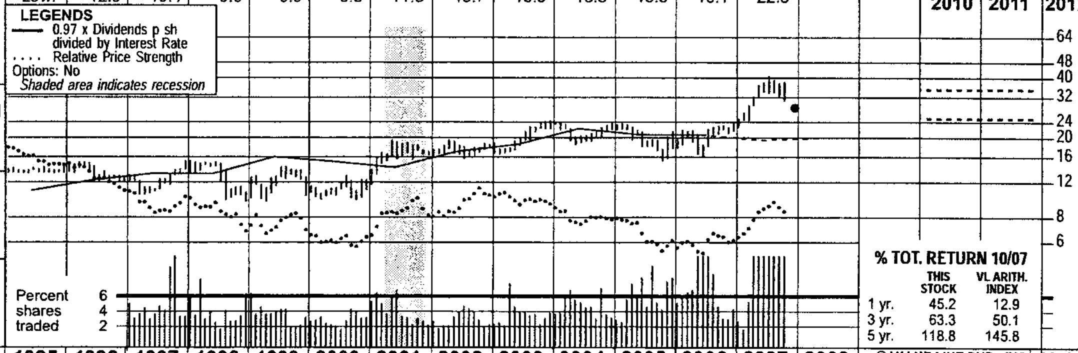
# CENT. VERMONT P.S. NYSE-CV

RECENT PRICE 28.30 | P/E RATIO 18.7 (Trailing: 18.0; Median: 14.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Lowered 11/16/07
SAFETY 3 Raised 9/7/01
TECHNICAL 3 Lowered 11/2/07
BETA 1.00 (1.00 = Market)

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 15.1 | 15.4 | 15.4 | 14.4 | 13.0 | 19.6 | 19.7 | 24.5 | 24.1 | 23.7 | 23.9 | 41.1 |
| Low: | 12.0 | 10.4 | 9.6 | 9.6 | 9.8 | 11.6 | 15.7 | 16.5 | 18.5 | 15.3 | 16.1 | 22.5 |

Target Price Range 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 35 | (+25%) | 9% |
| Low | 25 | (-10%) | 1% |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 37 | 49 | 62 |
| to Sell | 24 | 24 | 35 |
| Hld's(000) | 3322 | 3520 | 5009 |

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 45.2 | 12.9 |
| 3 yr. | 63.3 | 50.1 |
| 5 yr. | 118.8 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 21.60 | 24.59 | 24.16 | 23.63 | 24.87 | 25.24 | 26.68 | 26.51 | 36.61 | 29.02 | 26.05 | 25.84 | 25.92 | 24.78 | 25.35 | 32.15 | **32.05** | **33.65** | Revenues per sh | **35.50** |
| 2.77 | 2.96 | 2.94 | 2.69 | 2.97 | 2.97 | 2.81 | 1.64 | 2.76 | 2.60 | 2.39 | 3.01 | 2.80 | 2.56 | 1.42 | 3.41 | **3.00** | **3.15** | "Cash Flow" per sh | **3.30** |
| 1.65 | 1.71 | 1.64 | 1.29 | 1.47 | 1.41 | 1.32 | .18 | 1.28 | 1.14 | .93 | 1.54 | 1.41 | 1.25 | .08 | 1.63 | **1.40** | **1.50** | Earnings per sh A | **1.65** |
| 1.39 | 1.39 | 1.42 | 1.42 | .80 | .84 | .88 | .88 | .88 | .88 | .88 | .88 | .88 | .92 | .92 | .92 | **.92** | **.92** | Div'd Decl'd per sh B ■ | **.92** |
| 1.75 | 1.83 | 1.77 | 1.93 | 1.84 | 1.65 | 1.21 | 1.59 | 1.37 | 1.40 | 1.47 | 1.23 | 1.28 | 1.66 | 1.43 | 1.92 | **3.60** | **2.40** | Cap'l Spending per sh | **2.35** |
| 14.03 | 14.21 | 15.03 | 14.56 | 15.51 | 16.19 | 16.38 | 15.63 | 16.05 | 16.57 | 15.81 | 16.83 | 17.89 | 18.49 | 17.70 | 17.70 | **18.40** | **19.00** | Book Value per sh C | **21.20** |
| 10.81 | 11.20 | 11.56 | 11.73 | 11.59 | 11.52 | 11.42 | 11.46 | 11.47 | 11.51 | 11.61 | 11.74 | 11.81 | 12.19 | 12.28 | 10.13 | **10.30** | **10.40** | Common Shs Outst'g D | **10.70** |
| 11.4 | 12.6 | 14.3 | 12.3 | 9.3 | 9.5 | 9.3 | NMF | 9.5 | 9.7 | 17.8 | 11.4 | 14.3 | 17.1 | NMF | 12.7 | *Bold figures are* | | Avg Ann'l P/E Ratio | **18.0** |
| .73 | .76 | .84 | .81 | .62 | .60 | .54 | NMF | .54 | .63 | .91 | .62 | .82 | .90 | NMF | .69 | *Value Line* | | Relative P/E Ratio | **1.20** |
| 7.3% | 6.4% | 6.0% | 8.9% | 5.8% | 6.3% | 7.2% | 6.8% | 7.2% | 8.0% | 5.3% | 5.0% | 4.4% | 4.3% | 4.6% | 4.4% | *estimates* | | Avg Ann'l Div'd Yield | **3.1%** |

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 304.7 | 303.8 | 419.8 | 333.9 | 302.5 | 303.4 | 306.0 | 302.2 | 311.4 | 325.7 | **330** | **350** | Revenues ($mill) | **380** |
| 17.2 | 4.0 | 16.6 | 14.8 | 12.4 | 20.0 | 18.4 | 15.6 | 1.4 | 18.50 | **15.0** | **16.0** | Net Profit ($mill) | **18.0** |
| 34.8% | 3.5% | 38.5% | 39.5% | 43.4% | 37.8% | 32.0% | 18.4% | 18.4% | 35.1% | **35.0%** | **35.0%** | Income Tax Rate | **35.0%** |
| .6% | 2.5% | .2% | .7% | .7% | .5% | .7% | 1.3% | 7.4% | .8% | **1.0%** | **1.0%** | AFUDC % to Net Profit | **1.0%** |
| 34.0% | 34.1% | 44.9% | 43.7% | 45.5% | 41.0% | 37.6% | 35.8% | 34.7% | 39.2% | **40.0%** | **40.5%** | Long-Term Debt Ratio | **39.0%** |
| 57.7% | 57.5% | 48.5% | 50.0% | 48.4% | 54.1% | 57.8% | 60.4% | 61.8% | 57.3% | **57.0%** | **56.5%** | Common Equity Ratio | **58.0%** |
| 324.5 | 311.5 | 379.4 | 381.7 | 379.2 | 365.3 | 365.7 | 373.4 | 351.5 | 313.0 | **325** | **350** | Total Capital ($mill) | **390** |
| 321.6 | 319.9 | 314.7 | 311.0 | 308.6 | 304.6 | 298.7 | 299.5 | 301.2 | 308.8 | **330** | **335** | Net Plant ($mill) | **360** |
| 6.7% | 2.9% | 5.8% | 5.7% | 5.0% | 7.2% | 6.6% | 5.4% | 1.4% | 7.1% | **6.0%** | **5.5%** | Return on Total Cap'l | **6.0%** |
| 8.0% | 1.9% | 7.9% | 6.9% | 6.0% | 9.3% | 8.0% | 6.5% | .6% | 9.7% | **7.5%** | **7.5%** | Return on Shr. Equity | **7.5%** |
| 8.1% | 1.1% | 8.0% | 6.9% | 5.8% | 9.3% | 8.1% | 6.8% | .5% | 10.1% | **7.5%** | **8.0%** | Return on Com Equity E | **8.0%** |
| 2.4% | NMF | 2.5% | 1.5% | .5% | 3.9% | 3.2% | 1.5% | NMF | 4.6% | **2.5%** | **3.0%** | Retained to Com Eq | **3.5%** |
| 74% | NMF | 72% | 80% | 92% | 61% | 63% | 78% | NMF | 55% | **69%** | **62%** | All Div'ds to Net Prof | **57%** |

**CAPITAL STRUCTURE as of 6/30/07**
**Total Debt** $133.2 mill. **Due in 5 Yrs** $38.4 mill.
**LT Debt** $116.0 mill. **LT Interest** $7.8 mill.
Incl. $5.2 mill. capitalized leases.
(LT interest earned: 3.7x)
**Pension Assets-12/06** $86.1 mill. **Oblig.** $103.9 mill.
**Pfd Stock** $10.1 mill. **Pfd Div'd** $.4 mill.
Incl. 37,856 shs. 4.15%; 10,000 shs. 4.65%; 17,682 shs. 4.75%; 15,000 shs. 5.375%; 50,000 shs. 8.30%, all cum. and $100 par.
**Common Stock** 10,194,531 shs. **as of 7/31/07**

**MARKET CAP: $300 million (Small Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.0 | +2.6 | -.6 |
| Avg. Indust. Use (MWH) | 11327 | 11509 | 10015 |
| Avg. Indust. Revs. per KWH (¢) | 8.29 | 8.18 | 8.15 |
| Capacity at Peak (Mw) | 469 | NA | NA |
| Peak Load, Winter (Mw) | 427 | NA | NA |
| Annual Load Factor (%) | N/A | NA | NA |
| % Change Customers (yr-end) | +1.0 | +1.2 | +1.3 |
| Fixed Charge Cov. (%) | 247 | 61 | 334 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 1.0% | -2.0% | 4.5% |
| "Cash Flow" | -1.5% | -1.0% | 5.0% |
| Earnings | -3.5% | -2.5% | 9.0% |
| Dividends | -1.0% | 1.0% | Nil |
| Book Value | 1.5% | 2.0% | 3.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 84.1 | 67.6 | 72.8 | 77.7 | 302.2 |
| 2005 | 75.7 | 75.1 | 75.0 | 85.6 | 311.4 |
| 2006 | 82.3 | 79.0 | 79.9 | 84.5 | 325.7 |
| 2007 | 86.7 | 77.4 | 79.2 | **86.7** | **330** |
| 2008 | **91.0** | **81.0** | **87.0** | **91.0** | **350** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .51 | .26 | .34 | .14 | 1.25 |
| 2005 | d.41 | .21 | .22 | .06 | .08 |
| 2006 | .32 | .08 | .66 | .57 | 1.63 |
| 2007 | .55 | .04 | .41 | **.40** | **1.40** |
| 2008 | **.55** | **.15** | **.45** | **.35** | **1.50** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .22 | .22 | .22 | .22 | .88 |
| 2004 | .23 | .23 | .23 | .23 | .92 |
| 2005 | .23 | .23 | .23 | .23 | .92 |
| 2006 | .23 | .23 | .23 | .23 | .92 |
| 2007 | .23 | .23 | .23 | .23 | |

**BUSINESS:** Central Vermont Public Service Corporation supplies electricity to 153,000 customers in a large portion of Vermont. 2006 electric retail revenues: residential, 38%; commercial, 32%; industrial, 12%; other, 18%. '06 Generating sources: nuclear, 54%; hydro, 38%; other, 8%. Purchased power costs: 52% of '06 revenues. Owns 47% of Vermont Electric Power Company and has 29% entitlement to Vermont Yankee Nuclear plant output. Divested Connecticut Valley Electric Co., 1/04. '06 depreciation rate: 3.2%. Has 535 employees. Chairperson: Mary Alice McKenzie. President & Chief Executive Officer: Robert H. Young. Incorporated: Vermont. Address: 77 Grove St., Rutland, Vermont 05701. Telephone: 802-773-2711. Internet: www.cvps.com.

**Central Vermont Public Service awaits an order on its application for higher rates.** It asked for an increase of $12.6 million to be operative next February 1st. The hike is needed to offset a decline in prices received from the sale of excess energy into the wholesale market and to recover higher transmission costs. In addition, CV seeks to recoup 2007 capital expenditures that have been raised to $26 million from last year's $18 million and will likely remain at the higher level for some time to come. The proposal also includes a power cost adjustment mechanism and sharing of earnings with customers. Too, it recommends a plan for making rate adjustments over a three-year period without the need for periodic rate requests. A regulatory order on the filing is expected shortly.

**The company is heavily dependent on two energy sources.** CV receives 40% of its requirements from Entergy's Vermont Energy nuclear plant's output. The owner is expected to seek an extension of the operating license, which expires in 2012. Hydro Quebec provides another 29% of the company's needs, but it can reduce deliveries on one year's notice if hydro conditions worsen. Negotiations for renewal of both agreements are under way. To protect its supply, management is studying the feasibility of building a gas-fired plant with other utilities, is purchasing power on the wholesale market, and is buying energy from cow waste.

**We look for lower earnings in 2007.** Vermont Yankee's downtime for refueling hurt second-quarter results. Other negatives include the sale of excess power at low prices and a storm in April that boosted maintenance costs. Despite higher rates and fewer common shares outstanding, we estimate 2007 earnings will fall 14%, to $1.40 a share. An order on the aforementioned rate request points to improvement in 2008. The stock is untimely.

**These shares have little to offer utility investors.** The year-ahead yield is a full percentage point below the industry norm, and we don't expect a dividend hike in the scope of our 3- to 5-year horizon. What's more, it may be a while before major rating organizations restore CV's finances to an investment-grade level.

*Arthur H. Medalie* *November 30, 2007*

(A) Diluted egs. Excludes nonrecur.: '94, d14¢; '95, 4¢; '96, 10¢; '97, d7¢; '00, 28¢; '01, d87¢; '02, net d1¢; '03, 12¢; '04, 65¢; '05, 40¢. Next egs. report due mid-Feb. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. (C) Incl. def'd chgs. In '06: $5.65/sh. (D) In mill., adj'd for split. (E) Rate base: net orig. cost. Rate all'w com. eq. in '07: 10.75%; earned in '06: 8.9%. Reg. Clim.: Below Avg.

| | |
|---|---|
| Company's Financial Strength | B |
| Stock's Price Stability | 65 |
| Price Growth Persistence | 55 |
| Earnings Predictability | 30 |

# CLECO CORPORATION NYSE-CNL

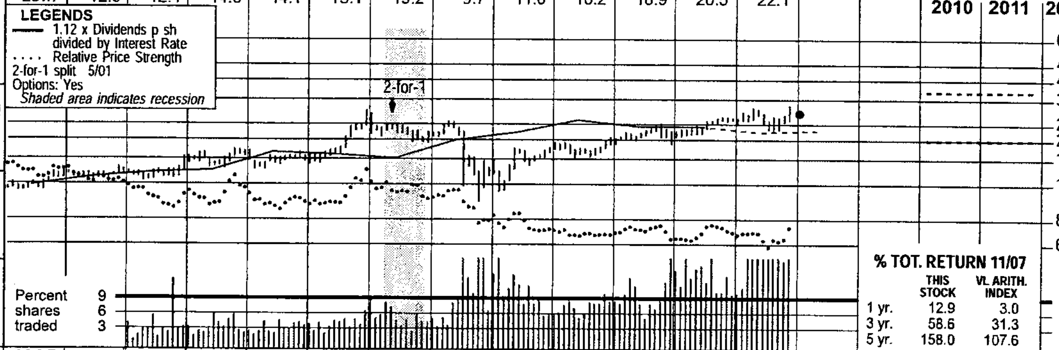
| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD |
|---|---|---|---|---|
| 27.25 | 18.0 | (Trailing: 21.0 / Median: 14.0) | 1.07 | 3.3% |

**VALUE LINE**

**TIMELINESS** 4 Raised 8/11/06
**SAFETY** 3 Lowered 1/3/03
**TECHNICAL** 3 Raised 12/28/07
**BETA** 1.15 (1.00 = Market)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 14.6 | 16.6 | 18.1 | 17.8 | 28.3 | 27.3 | 24.9 | 18.4 | 20.8 | 24.4 | 26.2 | 29.8 |
| Low: | 12.6 | 12.4 | 14.3 | 14.1 | 15.1 | 19.2 | 9.7 | 11.0 | 16.2 | 18.9 | 20.5 | 22.1 |

**Target Price Range** 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 35 | (+30%) | 10% |
| Low | 20 | (-25%) | -2% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 1 | 0 |
| to Sell | 0 | 0 | 0 | 10 | 0 | 0 | 0 | 1 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 88 | 96 | 97 |
| to Sell | 85 | 83 | 71 |
| Hld's(000) | 41756 | 48623 | 48236 |

**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 12.9 | 3.0 |
| 3 yr. | 58.6 | 31.3 |
| 5 yr. | 158.0 | 107.6 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7.58 | 7.88 | 8.54 | 8.48 | 8.79 | 9.70 | 10.16 | 11.46 | 17.12 | 18.23 | 23.55 | 15.33 | 18.54 | 15.03 | 18.41 | 17.38 | **17.10** | **18.85** | Revenues per sh | **23.00** |
| 1.76 | 1.78 | 1.74 | 1.85 | 1.99 | 2.11 | 2.18 | 2.28 | 2.36 | 2.77 | 2.94 | 3.05 | 2.98 | 2.56 | 2.76 | 2.70 | **2.85** | **3.05** | "Cash Flow" per sh | **4.00** |
| .96 | .97 | .89 | .96 | 1.04 | 1.12 | 1.09 | 1.12 | 1.19 | 1.46 | 1.51 | 1.52 | 1.26 | 1.32 | 1.42 | 1.36 | **1.30** | **1.50** | Earnings per sh A | **2.00** |
| .66 | .69 | .71 | .73 | .75 | .77 | .79 | .81 | .83 | .85 | .87 | .90 | .90 | .90 | .90 | .90 | **.90** | **.90** | Div'd Decl'd per sh B ■ † | **1.30** |
| 1.23 | 1.44 | 1.15 | 1.24 | 1.29 | 1.43 | 1.73 | 2.09 | 3.99 | 2.52 | 1.10 | 1.91 | 1.58 | 1.61 | 3.19 | 4.11 | **8.65** | **5.40** | Cap'l Spending per sh | **1.75** |
| 6.76 | 7.06 | 7.29 | 7.56 | 7.91 | 8.30 | 8.68 | 9.07 | 9.44 | 10.04 | 10.69 | 11.77 | 10.09 | 10.83 | 13.69 | 15.22 | **16.25** | **17.00** | Book Value per sh C | **19.50** |
| 44.48 | 44.61 | 44.77 | 44.78 | 44.85 | 44.91 | 44.93 | 44.97 | 44.88 | 44.99 | 44.96 | 47.04 | 47.18 | 49.62 | 49.99 | 57.57 | **60.00** | **61.00** | Common Shs Outst'g D | **64.00** |
| 10.7 | 12.5 | 14.3 | 12.1 | 11.6 | 11.9 | 12.5 | 14.4 | 13.4 | 13.2 | 14.6 | 12.2 | 12.4 | 13.8 | 15.0 | 17.3 | **Bold figures are** | | Avg Ann'l P/E Ratio | **14.0** |
| .68 | .76 | .84 | .79 | .78 | .75 | .72 | .75 | .76 | .86 | .75 | .67 | .71 | .73 | .80 | .93 | **Value Line** | | Relative P/E Ratio | **.95** |
| 6.4% | 5.7% | 5.5% | 6.2% | 6.2% | 5.8% | 5.8% | 5.0% | 5.2% | 4.4% | 3.9% | 4.8% | 5.8% | 5.0% | 4.2% | 3.8% | **estimates** | | Avg Ann'l Div'd Yield | **4.8%** |

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 456.2 | 515.2 | 768.2 | 820.0 | 1058.6 | 721.2 | 874.6 | 745.8 | 920.2 | 1000.7 | **1025** | **1150** | Revenues ($mill) | **1475** |
| 52.5 | 53.8 | 56.8 | 69.3 | 72.3 | 74.2 | 61.2 | 66.1 | 75.0 | 74.7 | **80.0** | **90.0** | Net Profit ($mill) | **130** |
| 34.6% | 33.1% | 32.4% | 33.5% | 34.7% | 36.9% | 37.2% | 35.2% | 39.2% | 36.0% | **38.5%** | **38.5%** | Income Tax Rate | **38.5%** |
| 1.5% | 3.2% | 10.6% | 12.1% | 16.7% | 12.6% | 5.8% | 7.5% | 4.3% | 14.2% | **53.0%** | **55.0%** | AFUDC % to Net Profit | **4.0%** |
| 46.2% | 43.6% | 56.2% | 57.9% | 55.2% | 60.0% | 64.4% | 44.5% | 46.3% | 40.9% | **45.5%** | **51.0%** | Long-Term Debt Ratio | **50.0%** |
| 49.2% | 51.9% | 41.0% | 39.7% | 42.4% | 38.2% | 33.8% | 53.1% | 52.0% | 57.8% | **54.5%** | **49.0%** | Common Equity Ratio | **50.0%** |
| 792.1 | 786.2 | 1032.1 | 1139.2 | 1134.7 | 1448.7 | 1408.5 | 1011.6 | 1315.9 | 1515.6 | **1790** | **2115** | Total Capital ($mill) | **2475** |
| 1025.6 | 1089.8 | 1211.6 | 1232.8 | 1224.7 | 1566.2 | 1417.1 | 1060.0 | 1188.7 | 1304.9 | **1740** | **1985** | Net Plant ($mill) | **2050** |
| 8.1% | 8.3% | 6.9% | 8.3% | 8.6% | 7.1% | 6.7% | 8.9% | 7.1% | 6.3% | **5.5%** | **6.0%** | Return on Total Cap'l | **7.0%** |
| 12.3% | 12.1% | 12.5% | 14.4% | 14.2% | 12.8% | 12.2% | 11.8% | 10.6% | 8.3% | **8.0%** | **9.0%** | Return on Shr. Equity | **10.5%** |
| 12.9% | 12.7% | 12.9% | 14.9% | 14.6% | 13.1% | 12.5% | 11.9% | 10.7% | 8.3% | **8.0%** | **9.0%** | Return on Com Equity E | **10.5%** |
| 3.9% | 3.8% | 4.2% | 6.5% | 6.5% | 5.6% | 3.5% | 3.9% | 4.1% | 3.0% | **2.5%** | **3.5%** | Retained to Com Eq | **3.5%** |
| 71% | 71% | 69% | 57% | 57% | 58% | 72% | 68% | 62% | 65% | **68%** | **60%** | All Div'ds to Net Prof | **64%** |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $779.1 mill. **Due in 5 Yrs** $275.5 mill.
**LT Debt** $654.1 mill. **LT Interest** $43.2 mill.
(LT interest earned: 3.4x)

**Leases, Uncapitalized** Annual rentals $5.4 mill.
**Pension Assets-12/06** $250.5 mill. **Oblig.** $267.3 mill.
**Pfd Stock** $1.0 mill. **Pfd Div'd** $.1 mill.
Includes 10,288 shares 8.125%, each convertible into 9.6 common shares, callable at $100.8125.
**Common Stock** 60,007,352 shs.
**as of 10/30/07**
**MARKET CAP: $1.6 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.6 | -.2 | +2.4 |
| Avg. Indust. Use (MWH) | 4194 | 4245 | 4496 |
| Avg. Indust. Revs. per KWH (¢) | 5.67 | 7.22 | 7.65 |
| Capacity at Peak (Mw) | 2190 | 2030 | 2124 |
| Peak Load, Summer (Mw) | 1940 | 2014 | 2137 |
| Annual Load Factor (%) | 60.0 | 57.2 | 56.0 |
| % Change Customers (avg.) | +1.8 | +.8 | +.5 |
| Fixed Charge Cov. (%) | 174 | 247 | 227 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 6.5% | -3.0% | 5.0% |
| "Cash Flow" | 3.0% | -.5% | 7.0% |
| Earnings | 3.0% | -- | 6.5% |
| Dividends | 2.0% | 1.0% | 6.5% |
| Book Value | 5.5% | 5.5% | 6.5% |

**QUARTERLY REVENUES ($ mill.)**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 166.6 | 166.3 | 229.4 | 183.5 | 745.8 |
| 2005 | 172.1 | 194.1 | 283.7 | 270.3 | 920.2 |
| 2006 | 223.4 | 251.0 | 294.1 | 232.2 | 1000.7 |
| 2007 | 223.8 | 261.5 | 311.7 | **228** | **1025** |
| 2008 | **255** | **285** | **350** | **260** | **1150** |

**EARNINGS PER SHARE A**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .26 | .22 | .56 | .27 | 1.32 |
| 2005 | .18 | .40 | .82 | .03 | 1.42 |
| 2006 | .23 | .44 | .50 | .19 | 1.36 |
| 2007 | .14 | .25 | .72 | **.19** | **1.30** |
| 2008 | **.25** | **.35** | **.65** | **.25** | **1.50** |

**QUARTERLY DIVIDENDS PAID B ■ †**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .225 | .225 | .225 | .225 | .90 |
| 2004 | .225 | .225 | .225 | .225 | .90 |
| 2005 | .225 | .225 | .225 | .225 | .90 |
| 2006 | .225 | .225 | .225 | .225 | .90 |
| 2007 | .225 | .225 | .225 | .225 | |

**BUSINESS:** Cleco Corporation is a holding company for Cleco Power, which supplies electricity to about 268,000 customers in central Louisiana. Through subsidiaries, has about 1,350 megawatts of wholesale capacity. Electric revenue breakdown, '06: residential, 46%; commercial, 23%; industrial, 16%; other, 15%. Largest industrial customers are paper mills and other wood-product industries. Generating sources, '06: coal & lignite, 31%; gas & oil, 13%; purchased, 56%. Fuel costs: 64% of revenues. '06 reported deprec. rate (utility): 3.3%. Has 1,200 employees. Chairman: J. Patrick Garrett. President & CEO: Michael H. Madison. Inc.: Louisiana. Address: P.O. Box 5000, Pineville, Louisiana 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

**Cleco's Rodemacher Unit 3 project is on schedule and on budget.** Cleco expects to spend $1 billion to build the 600-megawatt solid-fuel facility, which will probably use petroleum coke as the primary fuel source. The company will finance construction with the proceeds from a 2006 stock sale, debt, and the cash received from the resolution of a bankruptcy claim against Calpine (which was a partner in the Acadia gas-fired project that is still 50%-owned by Cleco). Once the plant enters commercial operation in the fourth quarter of 2009, it will lessen the utility's reliance on costly and volatile gas and purchased power. Even with the new plant, however, Cleco will still need additional capacity, so the company is now evaluating the submissions that resulted from its request for proposals.

**Cleco plans to file a rate case in the fourth quarter of 2008.** This would enable it to place Rodemacher 3 in rates. The new unit would essentially double the size of the utility's rate base. Cleco hasn't had a base rate increase since 1985, more than 20 years ago.

**A strong third-quarter earnings comparison probably wasn't enough to prevent a profit decline in the year that is just ending.** Earnings fell sharply in the first half of 2007 because in the first half of 2006 Cleco recorded income from Calpine's letters of credit following its bankruptcy filing. Also, in the second period of 2007, the utility incurred $0.06 a share in costs associated with a scheduled maintenance outage at a base-load generating plant. The stock is ranked 4 (Below Average) for Timeliness. Our share-net estimate is at the upper end of Cleco's guidance of $1.20-$1.30.

**We look for higher earnings in 2008.** There is likely to be an increase in the allowance for funds used during construction as the building of Rodemacher 3 continues. We expect modest growth in kilowatt-hour sales, too. Cleco has not yet established an earnings target for 2008.

**We don't recommend this stock.** Its yield is a bit below average for a utility, and dividend growth isn't likely to resume for a few years. Also, the stock is trading well within our 3- to 5-year Target Price Range.

*Paul E. Debbas, CFA* *December 28, 2007*

(A) Primary EPS through '96, then diluted. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; '07, $1.22; losses from disc. ops.: '00, 14¢; '01, 4¢. '04 & '05 EPS don't add due to rounding. Next egs. report due late Feb. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinv. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '06: $5.30/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '06: 11.65%; earned on avg. com. eq., '06: 9.3%. Regulatory Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 80 |
| Price Growth Persistence | 50 |
| Earnings Predictability | 70 |

# CON. EDISON NYSE-ED

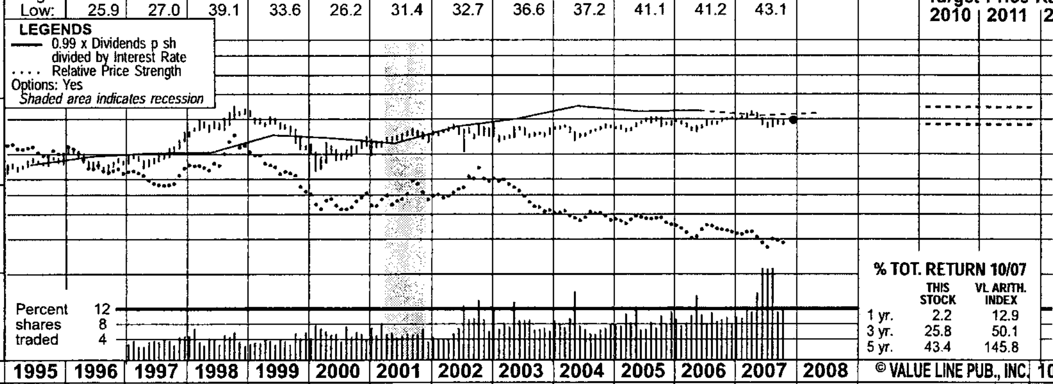
RECENT PRICE 47.50 | P/E RATIO 14.5 (Trailing: 13.6 Median: 14.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 3 Raised 8/11/06
SAFETY 1 New 7/27/90
TECHNICAL 4 Lowered 11/2/07
BETA .75 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 34.8 | 41.5 | 56.1 | 53.4 | 39.5 | 43.4 | 45.4 | 46.0 | 45.6 | 49.3 | 49.3 | 52.9 |
| Low: | 25.9 | 27.0 | 39.1 | 33.6 | 26.2 | 31.4 | 32.7 | 36.6 | 37.2 | 41.1 | 41.2 | 43.1 |

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 0.99 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 55 | (+15%) | 8% |
| Low | 45 | (-5%) | 3% |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 8 | 2 | 3 | 0 | 1 | 0 | 0 | 0 |
| to Sell | 0 | 1 | 2 | 3 | 0 | 2 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 211 | 200 | 222 |
| to Sell | 131 | 161 | 158 |
| Hld's(000) | 131243 | 130356 | 151880 |

Percent shares traded 12 8 4

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 2.2 | 12.9 |
| 3 yr. | 25.8 | 50.1 |
| 5 yr. | 43.4 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25.72 | 25.36 | 26.73 | 27.13 | 27.82 | 29.62 | 30.24 | 30.46 | 35.04 | 44.48 | 45.41 | 39.65 | 43.51 | 40.24 | 47.66 | 47.14 | *48.05* | *49.25* | Revenues per sh | *53.95* |
| 3.90 | 4.06 | 4.38 | 4.77 | 4.87 | 4.97 | 5.08 | 5.29 | 5.74 | 5.51 | 5.70 | 5.44 | 5.12 | 4.54 | 5.27 | 5.28 | *5.75* | *6.10* | "Cash Flow" per sh | *6.80* |
| 2.32 | 2.46 | 2.66 | 2.98 | 2.93 | 2.93 | 2.95 | 3.04 | 3.13 | 2.74 | 3.21 | 3.13 | 2.83 | 2.32 | 2.99 | 2.95 | *3.30* | *3.40* | Earnings per sh A | *3.50* |
| 1.86 | 1.90 | 1.94 | 2.00 | 2.04 | 2.08 | 2.10 | 2.12 | 2.14 | 2.18 | 2.20 | 2.22 | 2.24 | 2.26 | 2.28 | 2.30 | *2.32* | *2.34* | Div'd Decl'd per sh B ■ | *2.40* |
| 3.39 | 3.40 | 3.37 | 3.22 | 2.95 | 2.87 | 2.78 | 2.66 | 3.17 | 4.52 | 5.20 | 5.68 | 5.72 | 5.60 | 6.59 | 7.17 | *7.35* | *7.45* | Cap'l Spending per sh | *6.10* |
| 20.18 | 20.89 | 21.63 | 22.62 | 23.51 | 24.37 | 25.18 | 25.88 | 25.31 | 25.81 | 26.71 | 27.68 | 28.44 | 29.09 | 29.80 | 31.09 | *34.25* | *35.90* | Book Value per sh C | *40.60* |
| 228.33 | 233.93 | 234.37 | 234.91 | 234.96 | 234.99 | 235.49 | 232.83 | 213.81 | 212.03 | 212.15 | 213.93 | 225.84 | 242.51 | 245.29 | 257.46 | *272.00* | *273.00* | Common Shs Outst'g | *278.00* |
| 10.8 | 11.9 | 13.1 | 9.3 | 9.8 | 10.1 | 10.9 | 15.3 | 14.0 | 12.0 | 12.0 | 13.3 | 14.3 | 18.2 | 15.1 | 15.5 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.5* |
| .69 | .72 | .77 | .61 | .66 | .63 | .63 | .80 | .80 | .78 | .61 | .73 | .82 | .96 | .80 | .84 | *Value* | *Line* | Relative P/E Ratio | *.95* |
| 7.5% | 6.5% | 5.6% | 7.2% | 7.1% | 7.0% | 6.5% | 4.6% | 4.9% | 6.6% | 5.7% | 5.3% | 5.5% | 5.3% | 5.0% | 5.0% | *estimates* | | Avg Ann'l Div'd Yield | *4.8%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $9190 mill. **Due in 5 Yrs** $2905 mill.
**LT Debt** $7778 mill. **LT Interest** $505.0 mill.
(LT interest earned: 3.6x)
**Pension Assets-12/06** $8.1 bill. **Oblig.** $8.3 bill.

**Pfd Stock** $212.6 mill. **Pfd Div'd** $12.5 mill.
1,915,319 shs. $5 cum. no par, call. $105 a sh.; 375,626 shs. 4.65% cum. $100 par, call. $101 to $102.50 a sh. Sinking Fund ends 2009.

**Common Stock** 271,515,822 shs. **as of 10/31/07**
**MARKET CAP: $12.9 billion (Large Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7121.3 | 7093.1 | 7491.3 | 9431.4 | 9634.0 | 8482.0 | 9827.0 | 9758.0 | 11690 | 12137 | *13070* | *13450* | Revenues ($mill) | *15000* |
| 712.8 | 729.8 | 714.2 | 596.4 | 695.8 | 682.1 | 639.0 | 560.0 | 719.0 | 749.0 | *900* | *930* | Net Profit ($mill) | *980* |
| 34.8% | 35.8% | 34.3% | 34.8% | 40.0% | 36.9% | 33.7% | 34.3% | 33.6% | 35.2% | *35.0%* | *35.0%* | Income Tax Rate | *35.0%* |
| .9% | .5% | .8% | 1.2% | 1.3% | 2.2% | 4.2% | 7.7% | 2.2% | 1.6% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| 40.1% | 39.2% | 44.4% | 48.6% | 48.2% | 50.1% | 50.4% | 47.4% | 49.6% | 50.2% | *48.5%* | *48.0%* | Long-Term Debt Ratio | *47.0%* |
| 56.8% | 58.4% | 53.1% | 49.1% | 49.6% | 48.1% | 48.0% | 51.0% | 49.0% | 48.5% | *50.5%* | *51.0%* | Common Equity Ratio | *52.5%* |
| 10437 | 10325 | 10186 | 11137 | 11417 | 12302 | 13369 | 13828 | 14921 | 16515 | *18435* | *19220* | Total Capital ($mill) | *21605* |
| 11267 | 11407 | 11354 | 11893 | 12248 | 13329 | 15225 | 16106 | 17112 | 18445 | *18945* | *20245* | Net Plant ($mill) | *22960* |
| 8.4% | 8.6% | 8.6% | 7.0% | 7.8% | 7.1% | 6.3% | 5.6% | 6.3% | 6.0% | *6.5%* | *6.5%* | Return on Total Cap'l | *6.0%* |
| 11.4% | 11.6% | 12.6% | 10.4% | 11.8% | 11.1% | 9.6% | 7.7% | 9.6% | 9.1% | *9.5%* | *9.5%* | Return on Shr. Equity | *8.5%* |
| 11.7% | 11.8% | 12.9% | 10.7% | 12.0% | 11.3% | 9.8% | 7.8% | 9.7% | 9.2% | *9.5%* | *9.5%* | Return on Com Equity D | *8.5%* |
| 3.4% | 3.6% | 4.1% | 2.2% | 3.8% | 4.0% | 2.9% | .8% | 2.6% | 2.6% | *3.0%* | *3.0%* | Retained to Com Eq | *2.5%* |
| 72% | 70% | 69% | 80% | 69% | 65% | 71% | 89% | 74% | 73% | *71%* | *69%* | All Div'ds to Net Prof | *69%* |

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -2.8 | -1.8 | -1.9 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | 565 | 565 | 565 |
| Peak Load, Summer (Mw) | 11327 | 13059 | 13141 |
| Annual Load Factor (%) | NMF | NMF | NMF |
| % Change Customers (yr-end) | +.6 | +.8 | +.9 |
| Fixed Charge Cov. (%) | 257 | 312 | 291 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 5.0% | 1.5% | *3.0%* |
| "Cash Flow" | .5% | -2.5% | *5.0%* |
| Earnings | -.5% | -2.0% | *4.0%* |
| Dividends | 1.0% | 1.0% | *1.0%* |
| Book Value | 2.5% | 3.0% | *5.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 2679 | 2164 | 2734 | 2181 | 9758.0 |
| 2005 | 2801 | 2406 | 3375 | 3108 | 11690 |
| 2006 | 3317 | 2555 | 3441 | 2824 | 12137 |
| 2007 | 3418 | 3029 | 3643 | *2980* | *13070* |
| 2008 | *3600* | *2850* | *3800* | *3200* | *13450* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .69 | .38 | 1.03 | .22 | 2.32 |
| 2005 | .75 | .48 | 1.17 | .59 | 2.99 |
| 2006 | .74 | .51 | .92 | .78 | 2.95 |
| 2007 | .99 | .58 | 1.15 | *.58* | *3.30* |
| 2008 | *.90* | *.65* | *1.20* | *.65* | *3.40* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .56 | .56 | .56 | .56 | 2.24 |
| 2004 | .565 | .565 | .565 | .565 | 2.26 |
| 2005 | .57 | .57 | .57 | .57 | 2.28 |
| 2006 | .575 | .575 | .575 | .575 | 2.30 |
| 2007 | .58 | .58 | .58 | | |

**BUSINESS:** Consolidated Edison, Inc., parent of Consolidated Edison Company of New York, Inc., sells electricity (77% of revs.), gas (16%), steam (7%) in most of New York City and Westchester County. Acquired Orange & Rockland Utilities 7/99. Commercial rev. ratio (52%) compares with 32% for the industry. Nonincome taxes and avg. price per kwh are among the highest in U.S. Fuel costs: 66% of revenues; labor costs, 14%. 2006 reported deprec. rate: 2.9%. In '06, purchased almost all energy it sold on firm contracts with nonutility generators. Has 14,795 employes, Chairman, Chief Executive Officer & President: Kevin Burke. Incorporated: N.Y. Add.: 4 Irving Place, New York, N.Y. 10003. Tel.: 212-460-3903. Internet: www.coned.com.

**Consolidated Edison has received one rate order. A second is in the hopper.** Effective last October 1st, regulators raised the company's natural gas rates $67.5 million each year for three years. The increase provides for continued recovery of fuel costs and energy-efficiency programs. ED now awaits approval of its request for a $1.2 billion hike in electric delivery revenues for 2008. It also seeks a $335 million increase in 2009 and $390 million in 2010. The hikes are necessary to support planned expenditures of $2 billion annually for several years on the transmission and distribution system. New substations would be built, and those near the end of their lives would be upgraded or replaced. Finally, the demand-side management program would be expanded to reduce energy usage. An order on the filing is due next April 1st.

**Finances are among the strongest in the industry.** As of last July 31st, the retained earnings account stood at $5.9 billion, and it keeps rising. Though capital spending for the next few years will require substantial external financing, a solid balance sheet should enable ED to borrow at reasonable rates. What's more, the issuance of debt and equity will be in a mix that won't lower the common equity ratio. Too, even if the company loses an appeal of a $216 million IRS tax charge related to lease-in/lease-out transactions in 1997 and 1999, a loss would not have a serious adverse effect on finances.

**We look for improved earnings this year.** Pluses include last April's $220 million electric rate increase, the aforementioned boost in posted gas tariffs, and a projected 1.5% rise in energy sales. On the down side, increased borrowing will lift interest expense, more common shares will be outstanding, and capital investments will result in higher real estate taxes. In all, we estimate 2007 earnings will advance 12%, to $3.30 a share. A further increase in electric rates suggests another gain next year.

**The stock might interest conservative utility investors.** The company merits our highest Financial Strength rating of A++. And the yield is above average for a power equity. Moreover, dividend growth prospects are near those of the group.

*Arthur H. Medalie* *November 30, 2007*

(A) EPS diluted. Excl. nonrecur.: '02, (11¢); '03, (45¢). Next egs. report due late Jan. (B) Dividends historically paid in mid-Mar., mid-June, mid-Sept., and mid-Dec. ■ Div'd reinvest. plan avail. (C) Includes intangibles. In '06: $19.26/sh. (D) Rate base: net original cost. Rate all'd elec. common equity: '05, 11.4% to 13.0%; earned on '06 average common equity: 9.5%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 25 |
| Earnings Predictability | 85 |

# DTE ENERGY CO. NYSE-DTE

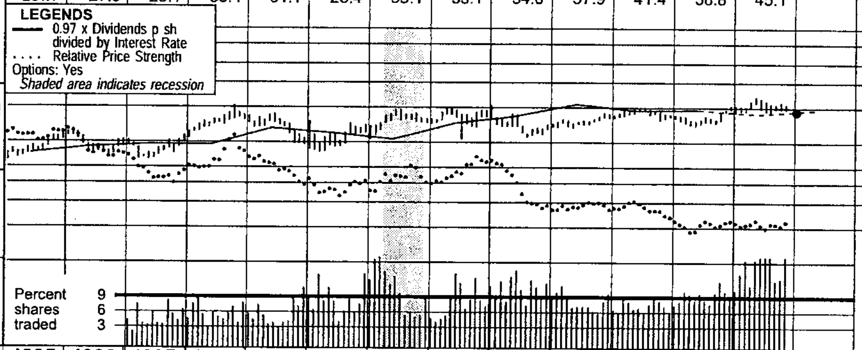
| RECENT PRICE | P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD |
|---|---|---|---|
| 45.88 | 13.6 (Trailing: 15.7 / Median: 13.0) | 0.80 | 4.8% |

**VALUE LINE**

**TIMELINESS** 3 Raised 9/15/06
**SAFETY** 3 Lowered 10/5/01
**TECHNICAL** 3 Lowered 12/29/06
**BETA** .80 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 37.3 | 34.8 | 49.3 | 44.7 | 41.3 | 47.1 | 47.7 | 49.5 | 45.5 | 48.3 | 49.2 | 54.7 | |
| Low: | 27.6 | 26.1 | 33.4 | 31.1 | 28.4 | 33.1 | 33.1 | 34.0 | 37.9 | 41.4 | 38.8 | 45.1 | |

**LEGENDS**
— 0.97 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



**Target Price Range**
2010 | 2011 | 2012
120 / 100 / 80 / 64 / 48 / 32 / 24 / 20 / 16 / 12 / 8

**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+30%) | 11% |
| Low | 40 | (-15%) | 2% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 2 | 0 | 2 | 0 | 0 | 2 | 0 | 0 |
| to Sell | 0 | 4 | 0 | 2 | 0 | 0 | 1 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 164 | 130 | 127 |
| to Sell | 125 | 153 | 156 |
| Hld's(000) | 109349 | 102976 | 97954 |

Percent shares traded 9 / 6 / 3

**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 8.8 | 3.0 |
| 3 yr. | 28.2 | 31.3 |
| 5 yr. | 38.8 | 107.6 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24.44 | 24.20 | 24.18 | 24.29 | 25.05 | 25.12 | 25.94 | 29.10 | 32.60 | 39.24 | 48.71 | 40.30 | 41.76 | 40.84 | 50.74 | 50.93 | *57.55* | *61.80* | Revenues per sh | *69.50* |
| 6.45 | 6.67 | 6.43 | 6.52 | 7.07 | 7.10 | 7.42 | 7.61 | 8.40 | 8.59 | 6.98 | 8.31 | 6.95 | 6.81 | 8.14 | 8.33 | *9.10* | *9.25* | "Cash Flow" per sh | *11.00* |
| 3.64 | 3.79 | 3.34 | 2.67 | 3.02 | 2.80 | 2.88 | 3.05 | 3.33 | 3.27 | 2.15 | 3.83 | 2.85 | 2.55 | 3.27 | 2.45 | *3.05* | *2.85* | Earnings per sh A | *3.50* |
| 1.88 | 1.98 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 | 2.08 | *2.12* | *2.18* | Div'd Decl'd per sh B ■ | *2.40* |
| 1.85 | 2.83 | 2.71 | 2.61 | 3.13 | 3.66 | 3.14 | 3.83 | 5.10 | 5.25 | 6.80 | 5.88 | 4.45 | 5.19 | 5.99 | 7.92 | *8.90* | *8.90* | Cap'l Spending per sh | *9.00* |
| 19.37 | 21.18 | 22.41 | 22.96 | 23.68 | 23.73 | 24.55 | 25.49 | 26.95 | 28.15 | 28.48 | 27.26 | 31.36 | 31.85 | 32.44 | 33.02 | *35.00* | *35.15* | Book Value per sh C | *38.00* |
| 146.98 | 147.02 | 147.05 | 144.86 | 145.12 | 145.12 | 145.10 | 145.07 | 145.04 | 142.65 | 161.13 | 167.46 | 168.61 | 174.21 | 177.81 | 177.14 | *162.50* | *157.00* | Common Shs Outst'g D | *157.00* |
| 8.3 | 8.5 | 10.2 | 10.0 | 10.0 | 11.2 | 10.3 | 13.3 | 11.6 | 10.3 | 19.3 | 11.3 | 13.7 | 16.0 | 13.8 | 17.4 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.0* |
| .53 | .52 | .60 | .66 | .67 | .70 | .59 | .69 | .66 | .67 | .99 | .62 | .78 | .85 | .73 | .94 | *Value Line* | | Relative P/E Ratio | *.95* |
| 6.2% | 6.1% | 6.0% | 7.7% | 6.9% | 6.6% | 6.9% | 5.1% | 5.3% | 6.1% | 5.0% | 4.8% | 5.3% | 5.0% | 4.6% | 4.9% | *estimates* | | Avg Ann'l Div'd Yield | *4.9%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $8496.0 mill. **Due in 5 Yrs** $3995.0 mill.
**LT Debt** $6961.0 mill. **LT Interest** $446.0 mill.
Incl. $44.0 mill. capitalized leases, $289.0 mill. Trust Preferred Securities, & $1.1 bill. securitized bonds.
(LT interest earned: 2.4x)

**Leases, Uncapitalized** Annual rentals $53.0 mill.
**Pension Assets-12/06** $2.74 bill. **Oblig.** $3.18 bill.
**Pfd Stock** None
**Common Stock** 163,713,691 shs.

**MARKET CAP: $7.5 billion (Large Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3764.0 | 4221.0 | 4728.0 | 5597.0 | 7849.0 | 6749.0 | 7041.0 | 7114.0 | 9022.0 | 9022.0 | *9350* | *9700* | Revenues ($mill) | *10900* |
| 429.0 | 449.0 | 483.0 | 468.0 | 329.0 | 632.0 | 480.0 | 443.0 | 576.0 | 437.0 | *520* | *455* | Net Profit ($mill) | *540* |
| 37.5% | 25.5% | 11.0% | 1.9% | -- | -- | -- | 27.1% | 26.0% | 23.9% | *35.0%* | *35.0%* | Income Tax Rate | *35.0%* |
| .5% | .9% | .8% | .6% | .9% | 4.9% | 1.3% | .7% | 1.0% | 3.4% | *2.0%* | *2.0%* | AFUDC % to Net Profit | *2.0%* |
| 51.4% | 53.9% | 50.9% | 50.3% | 63.3% | 63.0% | 59.2% | 57.8% | 55.1% | 56.1% | *54.5%* | *56.0%* | Long-Term Debt Ratio | *56.5%* |
| 46.7% | 46.1% | 49.1% | 49.7% | 36.7% | 37.0% | 40.8% | 42.2% | 44.9% | 43.9% | *45.5%* | *44.0%* | Common Equity Ratio | *43.5%* |
| 7620.0 | 8021.0 | 7961.0 | 8077.0 | 12517 | 12350 | 12956 | 13154 | 12849 | 13323 | *12550* | *12550* | Total Capital ($mill) | *13700* |
| 8934.0 | 6943.0 | 7148.0 | 7387.0 | 9543.0 | 9813.0 | 10324 | 10491 | 10830 | 11451 | *11975* | *12400* | Net Plant ($mill) | *13300* |
| 7.4% | 7.4% | 7.9% | 7.5% | 4.4% | 7.3% | 5.6% | 5.2% | 6.3% | 5.1% | *6.0%* | *5.5%* | Return on Total Cap'l | *5.5%* |
| 11.6% | 12.1% | 12.4% | 11.7% | 7.2% | 13.8% | 9.1% | 8.0% | 10.0% | 7.5% | *9.0%* | *8.0%* | Return on Shr. Equity | *9.0%* |
| 11.7% | 12.0% | 12.4% | 11.7% | 7.2% | 13.8% | 9.1% | 8.0% | 10.0% | 7.5% | *9.0%* | *8.0%* | Return on Com Equity E | *9.0%* |
| 3.3% | 3.9% | 4.7% | 4.3% | .1% | 6.4% | 2.5% | 1.6% | 3.7% | 1.2% | *3.0%* | *2.0%* | Retained to Com Eq | *3.0%* |
| 72% | 68% | 62% | 63% | 99% | 53% | 72% | 80% | 63% | 84% | *69%* | *77%* | All Div'ds to Net Prof | *70%* |

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -1.5 | +4.6 | +.5 |
| Avg. Indust. Use (MWH) | 15524 | 13609 | NA |
| Avg. Indust. Revs. per KWH (¢) | 4.86 | 5.66 | 6.31 |
| Capacity at Peak (Mw) | 11078 | 11113 | NA |
| Peak Load, Summer (Mw) | 9587 | 10938 | 12778 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +.7 | +.6 | +.4 |
| Fixed Charge Cov. (%) | 162 | 182 | 156 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 6.5% | 3.5% | 6.5% |
| "Cash Flow" | 1.0% | -.5% | 6.0% |
| Earnings | -.5% | -1.0% | 4.0% |
| Dividends | -- | -- | 2.5% |
| Book Value | 3.5% | 3.0% | 2.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 2093 | 1501 | 1594 | 1926 | 7114.0 |
| 2005 | 2309 | 1941 | 2060 | 2712 | 9022.0 |
| 2006 | 2635 | 1895 | 2196 | 2296 | 9022.0 |
| 2007 | 2730 | 1954 | 2417 | *2249* | *9350* |
| 2008 | *2850* | *2000* | *2500* | *2350* | *9700* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 1.15 | .20 | .54 | .68 | 2.55 |
| 2005 | .72 | .19 | .17 | 2.18 | 3.27 |
| 2006 | .76 | d.18 | 1.07 | .81 | 2.45 |
| 2007 | .76 | .17 | 1.19 | *.93* | *3.05* |
| 2008 | *.80* | *.45* | *.80* | *.80* | *2.85* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .515 | .515 | .515 | .515 | 2.06 |
| 2004 | .515 | .515 | .515 | .515 | 2.06 |
| 2005 | .515 | .515 | .515 | .515 | 2.06 |
| 2006 | .515 | .515 | .515 | .515 | 2.06 |
| 2007 | .53 | .53 | .53 | .53 | |

**BUSINESS:** DTE Energy Company is a holding company for The Detroit Edison Company, which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and Michigan Consolidated Gas (MichCon). Customers: 2.2 mill. electric, 1.3 mill. gas. Acq'd MCN Energy 6/01. Has various nonutility operations. Electric rev. breakdown, '06: residential, 35%; commercial, 34%; industrial, 18%; other, 13%. Generating sources, '06: coal, 67%; nuclear, 13%; oil & gas, 3%; purchased, 17%. Fuel costs: 34% of revs. '06 reported depr. rates: 3.3% elec., 2.8% gas. Has 9,100 employees. Chairman & CEO: Anthony F. Earley, Jr. President: Gerard M. Anderson. Inc.: MI. Address: 2000 Second Ave., Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

**DTE Energy's asset-monetization plan is making progress.** The latest announcement was the sale of some unconventional gas properties in Texas, which should net the company cash of $175 million. This deal, and the sale of a 50% stake in some power and industrial projects, should close in the first quarter of 2008. DTE has already sold some unconventional gas properties in Michigan and some gas-fired peaking power plants. These moves arose from the company's belief that the value of its nonregulated assets wasn't reflected in its stock price. In all, DTE expects this program to raise $1.7 billion, which it is using to buy back common stock and retire debt. It has repurchased most of the $1 billion of common stock it plans to buy back and intends to retire $700 million of debt. DTE still owns some unconventional gas acreage in Texas, but has to develop these properties before it becomes opportune to sell.

**Detroit Edison has a rate case pending.** The utility is seeking a rate hike of $199 million (4.7%) based on an 11.25% return on a common-equity ratio of 50%. An order is likely in the third quarter of 2008, unless the utility and intervenors can reach a settlement before then. The utility and its MichCon sibling will need additional rate relief in the next few years so that they can earn a return on the significant capital expenditures that they are making.

**An earnings decline appears likely in 2008.** DTE has been booking profits from its synthetic fuel investments. These are expected to produce net income of $150 million-$215 million in 2007. The synfuel program will cease at the end of 2007, however. A decline in average shares outstanding and the effects of any rate relief (and the expiration of a temporary rate cut in mid-April) at Detroit Edison should be positive factors for share net in 2008, but these probably won't be enough to replace the effect of the synfuel profits entirely.

**DTE stock offers an above-average yield, even for a utility, plus the likelihood of dividend growth over the 3- to 5-year period.** With the asset-sale program nearly complete, the stock is much more like a traditional utility investment. Total-return potential to 2010-2012 is only a bit above average for a utility, however.

*Paul E. Debbas, CFA* *December 28, 2007*

(A) Diluted EPS. Excl. nonrec. gains (losses): '01, 2¢; '03, (16¢); '05, (2¢); '06, 1¢; '07, $2.03; gain (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢). '04 EPS don't add due to change in shares, '05 & '06 due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Jan., April, July, and Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '06: $37.20/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. (elec.) in '04: 11%; gas in '05: 11%; earned on avg. com. eq., '06: 7.5%. Regul. Clim.: Below Avg.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 50 |

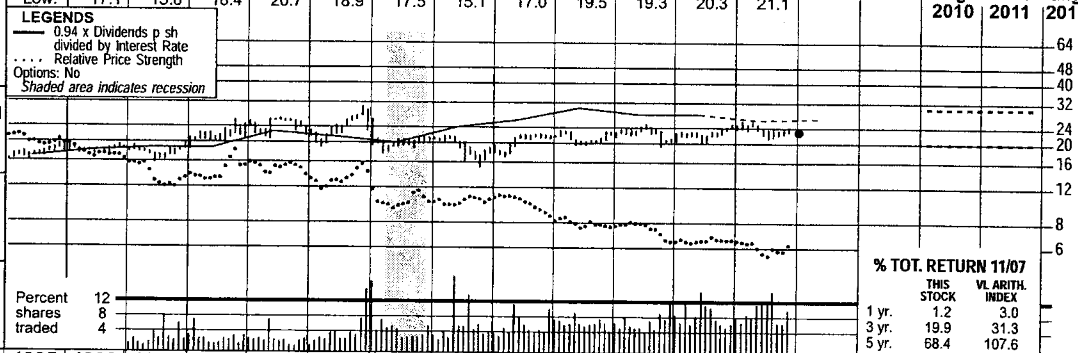
# EMPIRE DISTRICT NYSE-EDE

| RECENT PRICE | 22.87 | P/E RATIO | 17.9 (Trailing: 16.8; Median: 18.0) | RELATIVE P/E RATIO | 1.06 | DIV'D YLD | 5.6% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

TIMELINESS 3 Lowered 8/10/07
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Raised 12/7/07
BETA .85 (1.00 = Market)

| High: | 19.5 | 20.0 | 26.1 | 26.8 | 30.8 | 26.6 | 22.0 | 22.5 | 23.5 | 25.0 | 25.1 | 26.1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Low: | 17.1 | 15.8 | 18.4 | 20.7 | 18.9 | 17.5 | 15.1 | 17.0 | 19.5 | 19.3 | 20.3 | 21.1 |

Target Price Range 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 30 | (+30%) | 11% |
| Low | 20 | (-15%) | 3% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 50 | 63 | 44 |
| to Sell | 43 | 37 | 47 |
| Hld's(000) | 13362 | 14420 | 13678 |

**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 1.2 | 3.0 |
| 3 yr. | 19.9 | 31.3 |
| 5 yr. | 68.4 | 107.6 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11.58 | 11.31 | 12.41 | 12.75 | 12.67 | 12.53 | 12.83 | 14.02 | 13.94 | 14.78 | 13.37 | 13.56 | 13.03 | 12.67 | 14.80 | 13.67 | *14.30* | *14.25* | Revenues per sh | *16.00* |
| 2.68 | 2.55 | 2.49 | 2.62 | 2.52 | 2.67 | 2.67 | 2.97 | 2.89 | 3.12 | 2.19 | 2.43 | 2.48 | 2.22 | 2.45 | 2.80 | *2.70* | *2.95* | "Cash Flow" per sh | *3.75* |
| 1.43 | 1.26 | 1.16 | 1.32 | 1.18 | 1.23 | 1.29 | 1.53 | 1.13 | 1.35 | .59 | 1.19 | 1.29 | .86 | .92 | 1.41 | *1.25* | *1.45* | Earnings per sh A | *1.75* |
| 1.22 | 1.26 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | *1.28* | *1.28* | Div'd Decl'd per sh B ■ † | *1.35* |
| 1.79 | 2.36 | 3.27 | 5.14 | 3.34 | 3.79 | 3.38 | 3.03 | 4.14 | 7.61 | 4.02 | 3.43 | 2.65 | 1.64 | 2.83 | 3.97 | *5.50* | *5.70* | Cap'l Spending per sh | *2.75* |
| 12.08 | 12.29 | 12.37 | 12.47 | 12.69 | 12.96 | 13.06 | 13.43 | 13.48 | 13.65 | 13.58 | 14.59 | 15.17 | 14.76 | 15.08 | 15.49 | *16.10* | *16.65* | Book Value per sh C | *18.00* |
| 12.99 | 13.29 | 13.57 | 13.94 | 15.22 | 16.44 | 16.78 | 17.11 | 17.37 | 17.60 | 19.76 | 22.57 | 24.98 | 25.70 | 26.08 | 30.25 | *34.25* | *35.80* | Common Shs Outst'g D | *36.00* |
| 12.8 | 18.0 | 19.6 | 13.3 | 14.9 | 14.8 | 13.9 | 14.0 | 21.7 | 17.7 | 33.9 | 16.2 | 15.8 | 24.8 | 24.5 | 15.9 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.5* |
| .82 | 1.09 | 1.16 | .87 | 1.00 | .93 | .80 | .73 | 1.24 | 1.15 | 1.74 | .88 | .90 | 1.31 | 1.30 | .86 | *Value Line* | | Relative P/E Ratio | *.95* |
| 6.7% | 5.6% | 5.6% | 7.3% | 7.3% | 7.0% | 7.1% | 6.0% | 5.2% | 5.4% | 6.4% | 6.6% | 6.3% | 6.0% | 5.7% | 5.7% | *estimates* | | Avg Ann'l Div'd Yield | *5.3%* |
| | | | | | | 215.3 | 239.9 | 242.2 | 260.0 | 264.3 | 305.9 | 325.5 | 325.5 | 386.2 | 413.5 | *490* | *510* | Revenues ($mill) | *575* |
| | | | | | | 23.8 | 28.3 | 22.2 | 23.6 | 10.4 | 25.5 | 29.5 | 21.8 | 23.8 | 39.9 | *39.0* | *50.0* | Net Profit ($mill) | *65.0* |
| | | | | | | 50.8% | 36.4% | 41.9% | 32.7% | - - | 34.3% | 34.5% | 34.1% | 33.4% | 35.4% | *33.5%* | *33.5%* | Income Tax Rate | *35.5%* |
| | | | | | | 5.1% | 2.3% | 5.4% | 24.5% | 34.7% | 2.2% | 1.0% | 1.0% | 2.4% | 10.7% | *15.0%* | *11.0%* | AFUDC % to Net Profit | *2.0%* |
| | | | | | | 43.8% | 48.4% | 59.6% | 57.6% | 57.2% | 55.5% | 52.0% | 51.3% | 51.0% | 49.7% | *49.5%* | *50.0%* | Long-Term Debt Ratio | *49.5%* |
| | | | | | | 48.9% | 45.2% | 40.4% | 42.4% | 42.8% | 44.5% | 48.0% | 48.7% | 49.0% | 50.3% | *50.5%* | *50.0%* | Common Equity Ratio | *50.5%* |
| | | | | | | 448.3 | 508.5 | 580.0 | 565.8 | 626.9 | 740.3 | 789.2 | 779.1 | 803.3 | 931.0 | *1095* | *1200* | Total Capital ($mill) | *1275* |
| | | | | | | 547.0 | 572.2 | 616.0 | 720.3 | 750.5 | 794.1 | 833.9 | 857.0 | 896.0 | 1031.0 | *1170* | *1320* | Net Plant ($mill) | *1500* |
| | | | | | | 7.2% | 7.3% | 5.5% | 6.5% | 4.0% | 5.4% | 5.7% | 4.7% | 4.7% | 5.9% | *5.0%* | *5.5%* | Return on Total Cap'l | *7.0%* |
| | | | | | | 9.4% | 10.8% | 9.5% | 9.8% | 3.9% | 7.8% | 7.8% | 5.8% | 6.0% | 8.5% | *7.0%* | *8.5%* | Return on Shr. Equity | *10.5%* |
| | | | | | | 9.8% | 11.3% | 8.8% | 9.8% | 3.9% | 7.8% | 7.8% | 5.8% | 6.0% | 8.5% | *7.0%* | *8.5%* | Return on Com Equity E | *10.5%* |
| | | | | | | .1% | 1.8% | NMF | .5% | NMF | NMF | .1% | NMF | NMF | .8% | *NMF* | *1.0%* | Retained to Com Eq | *3.0%* |
| | | | | | | 99% | 85% | 107% | 95% | NMF | 109% | 99% | NMF | NMF | 90% | *106%* | *89%* | All Div'ds to Net Prof | *73%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $609.8 mill. **Due in 5 Yrs** $101.1 mill.
**LT Debt** $541.9 mill. **LT Interest** $36.5 mill.
Incl. $50 mill. 8.5% trust preferred securities.
(LT interest earned: 2.6x)
**Leases, Uncapitalized** Annual rentals $1.5 mill.
**Pension Assets-12/06** $126.8 mill. **Oblig.** $136.3 mill.
**Pfd Stock** None

**Common Stock** 30,546,570 shs.
**as of 11/1/07**

**MARKET CAP: $700 million (Small Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +.9 | +6.1 | +2.6 |
| Avg. Industrial Use (MWH) | 3040 | 3032 | 3096 |
| Avg. Industrial Rev/KWH (¢) | 4.78 | 5.38 | 5.66 |
| Capacity at Peak (Mw) | 1264 | 1264 | 1262 |
| Peak Load, Summer (Mw) | 1014 | 1087 | 1159 |
| Annual Load Factor (%) | 56.0 | 55.6 | 52.5 |
| % Change Customers (avg.) | +1.7 | +1.9 | +2.1 |
| Fixed Charge Cov. (%) | 214 | 224 | 273 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 1.0% | -.5% | 2.5% |
| "Cash Flow" | -.5% | -2.0% | 7.0% |
| Earnings | -1.5% | 1.0% | 8.5% |
| Dividends | - - | - - | 1.0% |
| Book Value | 1.5% | 2.0% | 3.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 77.2 | 77.3 | 96.7 | 74.3 | 325.5 |
| 2005 | 79.5 | 87.9 | 125.0 | 93.8 | 386.2 |
| 2006 | 84.0 | 91.7 | 131.2 | 106.6 | 413.5 |
| 2007 | 125.9 | 107.5 | 142.5 | *114.1* | *490* |
| 2008 | *130* | *110* | *150* | *120* | *510* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .06 | .08 | .64 | .08 | .86 |
| 2005 | d.01 | .12 | .75 | .05 | .92 |
| 2006 | .08 | .28 | .74 | .26 | 1.41 |
| 2007 | .15 | .19 | .76 | *.15* | *1.25* |
| 2008 | *.13* | *.24* | *.77* | *.31* | *1.45* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .32 | .32 | .32 | .32 | 1.28 |
| 2004 | .32 | .32 | .32 | .32 | 1.28 |
| 2005 | .32 | .32 | .32 | .32 | 1.28 |
| 2006 | .32 | .32 | .32 | .32 | 1.28 |
| 2007 | .32 | .32 | .32 | .32 | |

**BUSINESS:** The Empire District Electric Company supplies electricity to 165,000 customers in a 10,000 sq. mi. area in Missouri (89% of '06 retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (3%). Acq'd Missouri Gas (47,000 customers) 6/06. Supplies water service and has various nonregulated operations. Electric revenue breakdown, '06: residential, 42%; commercial, 30%; industrial, 17%; other, 11%. Generating sources, '06: coal, 46%; gas & oil, 17%; hydro, less than 1%; purchased, 37%. Fuel costs: 42% of revenues. '06 reported deprec. rate: 3.0%. Has about 700 employees. Chairman: Myron W. McKinney. President & CEO: William L. Gipson. Inc.: KS. Address: 602 Joplin St., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

**Empire District Electric has filed a rate case in Missouri.** The utility is seeking an electric tariff increase of $34.7 million (10.1%) based on an 11.6% return on equity. Empire District is seeking to place a 150-megawatt plant and other capital spending in the rate base. The utility also wants to recover $6.6 million in deferred expenses that stemmed from an ice storm in January. (Empire District swallowed an additional $4.4 million of storm-related costs.) Importantly, the company's application includes a fuel-adjustment clause, now that state law finally allows the commission to implement one. Empire District has requested a mechanism that would enable it to recover (or pass through to customers) 95% of changes in fuel costs over and above what is reflected in base rates. (It is asking for 95%, not 100%, because that's what Aquila's two utilities in Missouri received in a rate order earlier in 2007.) A decision by the Missouri commission is due by the start of September. Any rate relief will have just a modest benefit to earnings in 2008, because it will come too late for the seasonally strongest part of the year, but it should be a plus in 2009.

**Empire District sold some common stock.** The company sold three million shares, with an underwriters' option for an additional 450,000, for $23 each. This will help the utility finance its rising capital budget. Most notably, Empire District will have a 12% stake in a coal-fired unit that is scheduled to come on line in 2010.

**We have cut our earnings estimates for 2007 and 2008.** In December, Empire District's service area was hit with another ice storm. This will hurt earnings in the fourth quarter of 2007. In addition, an extended outage at a coal-fired plant will reduce net income by an estimated $4.0 million-$5.5 million in the fourth quarter of 2007 and the first period of 2008. Finally, in 2008 there will be some dilution from the aforementioned stock sale.

**This equity offers a yield that is well above average for a utility.** The payout is secure, especially since Empire District earned it in 2006 and will probably do so in 2008. In fact, we project some dividend growth through the 2010-2012 period, which should produce a total return over that time that exceeds the industry mean.

*Paul E. Debbas, CFA* *December 28, 2007*

(A) Excl. loss from discontinued operations: '06, 2¢. '05 EPS don't add due to rounding convention, '06 due to change in shares. Next earnings report due late Jan. (B) Div'ds historically paid in mid-March, June, Sept., and Dec. ■ Div'd reinvestment plan available (3% discount). † Shareholder investment plan available. (C) Incl. intangibles. In '06: $151.6 mill., $5.01/sh. (D) In millions. (E) Rate base: Deprec. original cost. Rate allowed on common equity in '07 (MO): 10.9%; earned on avg. com. eq., '06: 9.2%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 15 |
| Earnings Predictability | 50 |

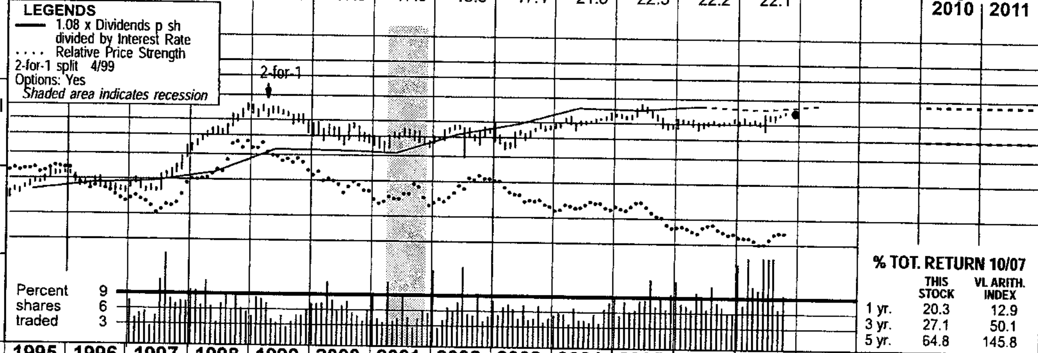
# ENERGY EAST CORP. NYSE-EAS

RECENT PRICE **27.45** | P/E RATIO **16.8** (Trailing: 16.1 / Median: 14.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **4.6%** | VALUE LINE

**TIMELINESS** – Suspended 7/6/07
**SAFETY** 2 Lowered 3/9/01
**TECHNICAL** – Suspended 7/6/07
**BETA** .80 (1.00 = Market)

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 13.2 | 17.9 | 29.0 | 28.6 | 23.6 | 22.1 | 23.1 | 23.7 | 27.1 | 30.1 | 25.7 | 27.9 |
| Low: | 10.2 | 10.3 | 16.5 | 20.6 | 17.9 | 17.0 | 15.8 | 17.4 | 21.8 | 22.5 | 22.2 | 22.1 |

Target Price Range 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 30 | (+10%) | 7% |
| Low | 20 | (-25%) | -1% |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 120 | 152 | 141 |
| to Sell | 91 | 80 | 116 |
| Hld's(000) | 80289 | 82460 | 88399 |

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 20.3 | 12.9 |
| 3 yr. | 27.1 | 50.1 |
| 5 yr. | 64.8 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12.27 | 12.18 | 12.75 | 13.28 | 14.05 | 14.78 | 15.78 | 19.85 | 20.84 | 25.15 | 32.21 | 27.65 | 31.41 | 32.33 | 35.87 | 35.36 | *32.90* | *34.20* | Revenues per sh | *39.75* |
| 2.37 | 2.32 | 2.20 | 2.43 | 2.54 | 2.64 | 2.77 | 3.06 | 3.37 | 3.42 | 3.75 | 3.12 | 4.28 | 4.18 | 4.33 | 4.67 | *4.30* | *4.45* | "Cash Flow" per sh | *5.00* |
| 1.18 | 1.20 | 1.04 | 1.19 | 1.25 | 1.26 | 1.29 | 1.51 | 1.91 | 2.07 | 2.00 | 1.50 | 1.43 | 1.62 | 1.74 | 1.76 | *1.60* | *1.60* | Earnings per sh A | *1.75* |
| 1.05 | 1.07 | 1.09 | 1.00 | .70 | .70 | .70 | .78 | .84 | .88 | .92 | .96 | 1.00 | 1.06 | 1.12 | 1.17 | *1.21* | *1.25* | Div'd Decl'd per sh B ■ | *1.45* |
| 1.92 | 1.75 | 1.88 | 1.72 | 1.14 | 1.54 | .92 | 1.04 | .64 | 1.32 | 1.79 | 1.55 | 1.98 | 2.07 | 2.26 | 2.79 | *3.15* | *3.50* | Cap'l Spending per sh | *4.50* |
| 11.08 | 11.42 | 11.44 | 11.64 | 12.19 | 12.70 | 13.36 | 13.61 | 12.84 | 14.59 | 15.26 | 16.97 | 17.59 | 17.89 | 19.45 | 19.37 | *20.05* | *20.40* | Book Value per sh C | *21.50* |
| 126.80 | 138.88 | 141.19 | 143.01 | 143.01 | 139.34 | 135.02 | 125.89 | 109.34 | 117.66 | 116.72 | 144.97 | 146.26 | 147.12 | 147.70 | 147.91 | *158.00* | *158.00* | Common Shs Outst'g D | *158.00* |
| 11.1 | 12.3 | 16.2 | 9.9 | 9.3 | 9.1 | 9.7 | 14.6 | 13.4 | 10.1 | 9.8 | 14.0 | 14.6 | 15.1 | 14.9 | 13.8 | *Bold figures are* | *Value Line* | Avg Ann'l P/E Ratio | *14.5* |
| .71 | .75 | .96 | .65 | .62 | .57 | .56 | .76 | .76 | .66 | .50 | .76 | .83 | .80 | .79 | .75 | *estimates* | | Relative P/E Ratio | *.95* |
| 8.0% | 7.3% | 6.5% | 8.5% | 6.0% | 6.1% | 5.6% | 3.5% | 3.3% | 4.2% | 4.7% | 4.6% | 4.8% | 4.3% | 4.3% | 4.8% | | | Avg Ann'l Div'd Yield | *5.5%* |
| | | | | | | 2130.0 | 2499.4 | 2278.6 | 2959.5 | 3759.8 | 4008.9 | 4593.8 | 4756.7 | 5298.5 | 5230.7 | *5200* | *5400* | Revenues ($mill) | *6300* |
| | | | | | | 184.6 | 202.8 | 225.1 | 237.6 | 235.4 | 199.6 | 212.1 | 241.3 | 258.3 | 261.0 | *250* | *255* | Net Profit ($mill) | *285* |
| | | | | | | 38.9% | 40.4% | 36.7% | 39.7% | 44.2% | 34.1% | 37.6% | 51.0% | 39.7% | 37.3% | *38.5%* | *38.5%* | Income Tax Rate | *38.5%* |
| | | | | | | .4% | .2% | .1% | .4% | .3% | .7% | .9% | .2% | .6% | .8% | *1.0%* | *1.0%* | AFUDC % to Net Profit | *1.0%* |
| | | | | | | 42.5% | 44.8% | 46.6% | 57.1% | 60.7% | 58.9% | 59.8% | 58.6% | 55.9% | 56.3% | *53.0%* | *53.0%* | Long-Term Debt Ratio | *54.5%* |
| | | | | | | 52.8% | 53.5% | 53.0% | 41.8% | 38.4% | 39.2% | 38.5% | 40.6% | 43.8% | 43.3% | *46.5%* | *47.0%* | Common Equity Ratio | *45.0%* |
| | | | | | | 3413.0 | 3203.0 | 2649.2 | 4106.7 | 4640.8 | 6273.5 | 6681.3 | 6475.6 | 6564.4 | 6615.6 | *6820* | *6880* | Total Capital ($mill) | *7550* |
| | | | | | | 3922.3 | 3862.7 | 2139.8 | 3632.9 | 3626.4 | 4801.8 | 5778.1 | 5662.2 | 5783.5 | 5948.0 | *6145* | *6380* | Net Plant ($mill) | *7275* |
| | | | | | | 7.0% | 7.9% | 10.5% | 7.4% | 7.2% | 5.1% | 5.1% | 5.5% | 5.7% | 5.8% | *5.5%* | *5.5%* | Return on Total Cap'l | *5.5%* |
| | | | | | | 9.4% | 11.5% | 15.9% | 13.5% | 12.9% | 7.7% | 7.9% | 9.0% | 8.9% | 9.0% | *8.0%* | *8.0%* | Return on Shr. Equity | *8.5%* |
| | | | | | | 9.7% | 11.3% | 15.8% | 13.8% | 13.1% | 8.0% | 8.1% | 9.0% | 8.9% | 9.1% | *8.0%* | *8.0%* | Return on Com Equity E | *8.5%* |
| | | | | | | 4.4% | 5.5% | 8.8% | 8.0% | 7.1% | 2.9% | 3.1% | 3.8% | 3.7% | 3.2% | *2.0%* | *2.0%* | Retained to Com Eq | *2.0%* |
| | | | | | | 57% | 54% | 45% | 42% | 46% | 65% | 63% | 58% | 59% | 65% | *75%* | *78%* | All Div'ds to Net Prof | *78%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $4024.9 mill. **Due in 5 Yrs** $1060.7 mill.
**LT Debt** $3689.7 mill. **LT Interest** $221.4 mill.
(LT interest earned: 2.7x)

**Pension Assets-12/06** $2.82 bill. **Oblig.** $2.31 bill.
**Pfd Stock** $24.6 mill. **Pfd Div'd** $1.1 mill.
242,524 shs. 3.75%-6.00%, cum., $100 par, redeemable at $100-$110; 108,706 shs. 8.0%, cum., $3.125 par, noncallable.

**Common Stock** 158,278,536 shs.
as of 10/31/07
**MARKET CAP: $4.3 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +1.4 | +3.2 | -2.8 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 3.82 | 3.66 | 3.81 |
| Capacity at Peak (Mw) | NMF | NMF | NMF |
| Peak Load, Winter (Mw) | NA | NA | NA |
| Annual Load Factor (%) | NMF | NMF | NMF |
| % Change Customers (yr-end) | +.9 | +.9 | +1.0 |
| Fixed Charge Cov. (%) | 264 | 238 | 225 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 9.5% | 6.0% | 2.5% |
| "Cash Flow" | 5.5% | 4.5% | 2.0% |
| Earnings | 3.5% | -3.0% | .5% |
| Dividends | 3.5% | 5.0% | 4.0% |
| Book Value | 4.5% | 6.0% | 2.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 1551.4 | 968.9 | 967.8 | 1268.9 | 4756.7 |
| 2005 | 1637 | 1082 | 1096 | 1483 | 5298.5 |
| 2006 | 1696 | 1113 | 1090 | 1332 | 5230.7 |
| 2007 | 1714 | 1089 | 1031 | *1366* | *5200* |
| 2008 | *1750* | *1150* | *1100* | *1400* | *5400* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .83 | .29 | .12 | .38 | 1.62 |
| 2005 | 1.05 | .12 | .14 | .43 | 1.74 |
| 2006 | .90 | .19 | .14 | .53 | 1.76 |
| 2007 | .90 | .12 | .16 | *.42* | *1.60* |
| 2008 | *.90* | *.15* | *.10* | *.45* | *1.60* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .25 | .25 | .25 | .25 | 1.00 |
| 2004 | .26 | .26 | .26 | .275 | 1.06 |
| 2005 | .275 | .275 | .275 | .275 | 1.10 |
| 2006 | .29 | .29 | .29 | .30 | 1.17 |
| 2007 | .30 | .30 | .30 | .31 | |

**BUSINESS:** Energy East Corporation is a holding company for New York State Electric & Gas (NYSEG), Rochester Gas and Electric, Central Maine Power, Connecticut Natural Gas, & Southern Connecticut Gas. Serves 1.8 million electric, 921,000 gas customers in NY & New England. Acq'd Connecticut Energy 2/00; CMP Group, CTG Resources & Berkshire Energy 9/00; RGS Energy 6/02. Electric revenue breakdown, '06: residential, 45%; commercial, 20%; industrial, 10%; other, 25%. Purchases most of its power. Fuel costs: 57% of revenues. '06 reported deprec. rate: 3.1%. Has 5,900 employees. Chairman, Pres. & CEO: Wesley W. von Schack. Inc.: New York. Address: 52 Farm View Dr., New Gloucester, Maine 12212-2904. Tel.: 207-688-6300. Internet: www.energyeast.com.

**Energy East shareholders have approved the takeover of the company by IBERDROLA,** a Spanish company. Under the agreement, Energy East stockholders will receive $28.50 in cash for each of their shares. The deal still requires the approval of the Federal Energy Regulatory Commission and the regulatory commissions in New York, Maine, Connecticut, and New Hampshire. It should be completed in the first half of 2008.

**The price is very fair for Energy East shareholders,** at nearly 18 times estimated 2007 and 2008 earnings. The Timeliness rank of Energy East stock remains suspended due to the positive influence that the deal has on the share price.

**We now advise shareholders to sell their stock on the open market.** The current quotation is just 4% below the buyout price, leaving little upside potential for stockholders who wait for completion of the transaction. And, given the regulatory approvals that are still pending, completion is by no means certain. If the deal fails to win regulatory approval, the stock will probably fall — perhaps to the low $20 range. Thus, shareholders can avoid downside risk by selling now.

**The capital budget will be rising in the coming years.** Energy East's utilities in upstate New York and Maine want to install advanced meter reading systems. The company is also planning transmission projects in these two states. Finally, Rochester Gas and Electric proposes to build a gas-fired plant to replace an old, coal-fired facility and meet the increased demand for power that is expected in the 2013-2014 time frame. In all, Energy East projects to spend over $3 billion in the next five years. IBERDROLA could provide capital to help finance these projects. But the utilities will need regulatory support to maintain the company's return on equity.

**We have raised our 2007 earnings estimate by $0.10 a share, to $1.60.** This merely reflects a better-than-expected tally in the September quarter. Note, too, that in early October the board of directors boosted the quarterly dividend by a cent a share, as we had expected. For now, we're sticking with our $1.60-a-share earnings estimate for 2008.

*Paul E. Debbas, CFA* *November 30, 2007*

(A) Diluted EPS. Excl. nonrecurring losses: '00, 40¢; '01, 39¢; '02, 6¢; gain (loss) from discontinued operations: '03, 2¢; '04, (5¢). Next earnings report due early Feb. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '06: $20.70/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. for NYSEG in '07: 9.55% elec., 10.5% gas; RG&E in '04: 12.25% elec., 12% gas; earned on avg. com. eq., '06: 8.9%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 85 |

# FIRSTENERGY NYSE-FE

| RECENT PRICE | 67.74 | P/E RATIO | 16.0 (Trailing: 16.1 / Median: 13.0) | RELATIVE P/E RATIO | 0.95 | DIV'D YLD | 3.1% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

| | |
|---|---|
| TIMELINESS | 3 Raised 5/5/06 |
| SAFETY | 2 Raised 6/2/06 |
| TECHNICAL | 3 Lowered 9/28/07 |
| BETA | .85 (1.00 = Market) |

**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 80 | (+20%) | 7% |
| Low | 60 | (-10%) | 1% |

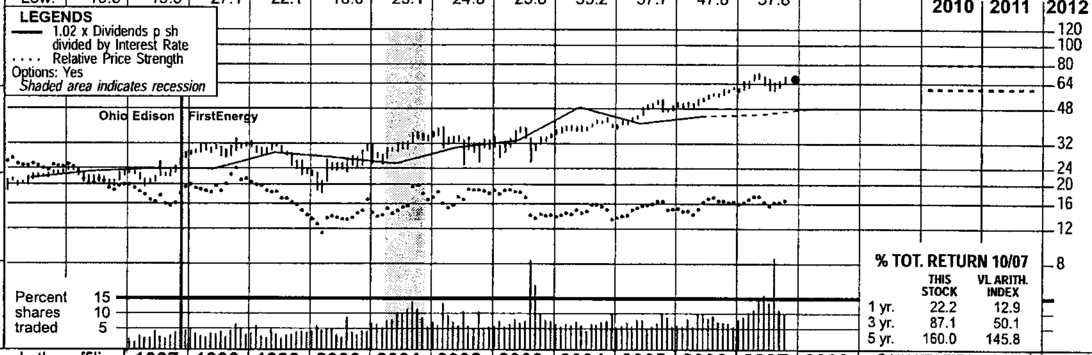
**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 1 | 1 | 18 | 1 | 0 | 0 | 2 | 2 |
| to Sell | 0 | 1 | 1 | 15 | 0 | 5 | 0 | 3 | 1 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 213 | 199 | 200 |
| to Sell | 164 | 195 | 202 |
| Hld's(000) | 229031 | 229298 | 237675 |

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 24.9 | 29.0 | 34.1 | 33.2 | 32.1 | 37.0 | 39.1 | 38.9 | 43.4 | 53.4 | 61.7 | 72.9 |
| Low: | 19.3 | 19.3 | 27.1 | 22.1 | 18.0 | 25.1 | 24.8 | 25.8 | 35.2 | 37.7 | 47.8 | 57.8 |




FirstEnergy was formed through the affiliation of Ohio Edison Company and Centerior Energy in November of 1997. Ohio Edison stockholders received one share of FirstEnergy for every Ohio Edison share, and Centerior stockholders received .52 of a FirstEnergy share for each Centerior share. In November of 2001, FirstEnergy acquired GPU. GPU holders received $40 in cash or stock for each GPU share. Data prior to 1998 reflect Ohio Edison on a stand-alone basis and are not comparable with FirstEnergy data.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12.26 | 24.72 | 27.19 | 31.31 | 26.88 | 40.83 | 37.31 | 37.76 | 36.35 | 36.03 | **41.50** | **41.50** | Revenues per sh | **46.00** |
| 3.66 | 5.33 | 6.89 | 7.28 | 5.48 | 6.45 | 4.79 | 7.60 | 7.55 | 7.22 | **7.70** | **8.10** | "Cash Flow" per sh | **9.25** |
| 1.94 | 1.95 | 2.50 | 2.69 | 2.84 | 2.54 | 1.47 | 2.77 | 2.84 | 3.82 | **4.25** | **4.30** | Earnings per sh A | **5.25** |
| 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.91 | 1.71 | 1.85 | **2.03** | **2.15** | Div'd Decl'd per sh B ■ † | **2.50** |
| .89 | 2.75 | 2.69 | 2.74 | 2.86 | 3.35 | 2.60 | 2.57 | 3.66 | 4.12 | **5.50** | **6.40** | Cap'l Spending per sh | **4.50** |
| 18.07 | 18.77 | 19.63 | 20.72 | 24.86 | 23.92 | 25.13 | 26.04 | 27.86 | 28.30 | **28.95** | **31.10** | Book Value per sh C | **38.75** |
| 230.21 | 237.07 | 232.45 | 224.53 | 297.64 | 297.64 | 329.84 | 329.84 | 329.84 | 319.21 | **304.80** | **304.80** | Common Shs Outst'g D | **304.80** |
| 11.8 | 15.4 | 11.3 | 9.2 | 10.9 | 13.0 | 22.5 | 14.1 | 16.1 | 14.2 | *Bold figures are* | | Avg Ann'l P/E Ratio | **13.5** |
| .68 | .80 | .64 | .60 | .56 | .71 | 1.28 | .74 | .86 | .77 | *Value Line* | | Relative P/E Ratio | **.90** |
| 6.6% | 5.0% | 5.3% | 6.1% | 4.8% | 4.6% | 4.5% | 4.9% | 3.7% | 3.4% | *estimates* | | Avg Ann'l Div'd Yield | **3.5%** |
| 2821.4 | 5861.3 | 6319.6 | 7029.0 | 7999.4 | 12152 | 12307 | 12453 | 11989 | 11501 | **12650** | **12650** | Revenues ($mill) | **14000** |
| 333.6 | 507.2 | 644.8 | 661.7 | 727.0 | 827.6 | 490.8 | 932.6 | 951.0 | 1265.0 | **1300** | **1310** | Net Profit ($mill) | **1610** |
| 38.4% | 38.8% | 38.0% | 36.3% | 39.5% | 41.5% | 43.9% | 42.2% | 42.1% | 38.6% | **41.0%** | **41.0%** | Income Tax Rate | **41.0%** |
| 1.0% | 1.5% | 2.1% | 4.1% | 4.9% | 3.0% | 6.5% | 2.7% | 2.0% | 2.1% | **2.0%** | **2.0%** | AFUDC % to Net Profit | **1.0%** |
| 57.5% | 54.0% | 52.3% | 52.3% | 60.1% | 60.2% | 53.1% | 52.8% | 46.5% | 48.6% | **50.5%** | **50.0%** | Long-Term Debt Ratio | **48.0%** |
| 34.3% | 37.8% | 39.8% | 41.5% | 37.2% | 38.0% | 45.0% | 45.4% | 52.4% | 51.4% | **49.5%** | **50.0%** | Common Equity Ratio | **52.0%** |
| 12124 | 11756 | 11470 | 11205 | 19907 | 18756 | 18414 | 18938 | 17527 | 17570 | **17900** | **18950** | Total Capital ($mill) | **22800** |
| 9573.2 | 9242.6 | 9093.3 | 7575.1 | 12428 | 12680 | 13269 | 13478 | 13998 | 14667 | **14325** | **15275** | Net Plant ($mill) | **16200** |
| 3.8% | 6.4% | 7.8% | 7.9% | 4.9% | 6.3% | 4.6% | 6.5% | 7.1% | 9.0% | **8.5%** | **8.5%** | Return on Total Cap'l | **8.5%** |
| 6.5% | 9.4% | 11.8% | 12.4% | 9.2% | 11.1% | 5.7% | 10.4% | 10.1% | 14.0% | **15.0%** | **14.0%** | Return on Shr. Equity | **13.5%** |
| 7.4% | 9.9% | 12.5% | 12.9% | 8.9% | 10.5% | 5.4% | 10.6% | 10.2% | 13.9% | **15.0%** | **14.0%** | Return on Com Equity E | **13.5%** |
| 1.6% | 2.3% | 5.0% | 5.7% | 4.3% | 4.3% | NMF | 4.9% | 4.2% | 7.4% | **7.5%** | **7.0%** | Retained to Com Eq | **7.0%** |
| 80% | 80% | 65% | 60% | 56% | 63% | 101% | 55% | 59% | 47% | **49%** | **50%** | All Div'ds to Net Prof | **47%** |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $11455 mill. **Due in 5 Yrs** $5297.0 mill.
**LT Debt** $8617.0 mill. **LT Interest** $517.0 mill.
Incl. $284.8 mill. 9% ($25 par) cumulative mandatorily redeemable preferred securities.
(LT interest earned: 4.4x)
**Leases, Uncapitalized** Annual rentals $204.0 mill.
**Pension Assets-12/06** $4.82 bill. **Oblig.** $4.86 bill.
**Pfd Stock** None
**Common Stock** 304,835,407 shs. **as of 10/31/07**
**MARKET CAP: $21 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -.6 | +5.2 | +6.7 |
| Avg. Indust. Use (MWH) | NMF | NMF | NMF |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | NA | NA | NA |
| Annual Load Factor (%) | 66.7 | 62.1 | NA |
| % Change Customers (yr-end) | +1.1 | +.8 | +.5 |
| Fixed Charge Cov. (%) | 316 | 299 | 355 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 8.5% | 5.0% | 4.0% |
| "Cash Flow" | 6.0% | 2.5% | 3.5% |
| Earnings | 4.5% | 3.5% | 9.0% |
| Dividends | 2.0% | 4.0% | 5.5% |
| Book Value | 5.5% | 4.5% | 6.0% |

| Calendar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 3027 | 3041 | 3435 | 2950 | 12453 |
| 2005 | 2750 | 2843 | 3504 | 2892 | 11989 |
| 2006 | 2705 | 2751 | 3365 | 2680 | 11501 |
| 2007 | 2973 | 3109 | 3641 | **2927** | **12650** |
| 2008 | **2900** | **3100** | **3700** | **2950** | **12650** |

| Calendar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .53 | .62 | .91 | .71 | 2.77 |
| 2005 | .42 | .76 | 1.01 | .65 | 2.84 |
| 2006 | .67 | .93 | 1.40 | .84 | 3.82 |
| 2007 | .92 | 1.10 | 1.34 | **.89** | **4.25** |
| 2008 | **.90** | **1.10** | **1.35** | **.95** | **4.30** |

| Calendar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .375 | .375 | .375 | .375 | 1.50 |
| 2004 | .375 | .375 | .375 | .375 | 1.50 |
| 2005 | .413 | .413 | .413 | .43 | 1.67 |
| 2006 | .45 | .45 | .45 | .45 | 1.80 |
| 2007 | .50 | .50 | .50 | | |

**BUSINESS:** FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, and Jersey Central Power & Light. Provides electric service to 4.5 million customers in Ohio (58% of revenues), New Jersey (22%) and Pennsylvania (20%). Electric revenue breakdown by customer class not provided by company. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 37% of revenues. '06 reported deprec. rates: 2.1%-4.1%. Has 13,700 employees. Chairman: George M. Smart. President & CEO: Anthony J. Alexander. COO: Richard R. Grigg. Inc.: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Tel.: 330-384-5100. Internet: www.firstenergycorp.com.

**Distribution rate cases are pending at FirstEnergy's three utilities in Ohio.** Ohio Edison, Cleveland Electric, and Toledo Edison are seeking base rate hikes totaling $332 million, based on a return of 11.75% on a common-equity ratio of 49%. The utilities are seeking recovery of higher costs and expenses that were deferred under previous regulatory plans. An order is due by March of 2008. New rates would take effect at the start of 2009 for Ohio Edison and Toledo Edison, and in May of 2009 for Cleveland Electric.

**Two of FirstEnergy's utilities in Pennsylvania have appealed a regulatory ruling to the courts.** The Pennsylvania commission rejected the request of MetEd and Penelec for a total of $219 million in rate relief associated with power generation. A court decision is expected in 2008.

**Earnings should wind up much higher in 2007.** Earlier this year, FirstEnergy executed a sale/leaseback transaction for its largest coal-fired unit. The deal raised $1.2 billion, $900 million of which was used to repay short-term debt that was used to fund a stock buyback. Also, FirstEnergy's generating assets are earning higher margins on the power they are supplying to the company's Penn Power subsidiary, since Penn Power made its scheduled transition to market-based rates. This should benefit share net by $0.12.

**There's a lot of uncertainty in our earnings estimate for 2008.** Higher kilowatt-hour sales and margins on power generation should be pluses, but higher transition-cost amortization will be a minus. Operating and maintenance expenses could go either way. We're tentatively estimating a slight earnings increase. FirstEnergy plans to issue 2008 earnings guidance in early December.

**We expect a dividend hike at the next board meeting, in December.** We estimate that the directors will raise the quarterly dividend by $0.03 a share (6%), to $0.53. That would be below recent increases, but would still be a very healthy rate of growth.

**We think FirstEnergy's solid earnings- and dividend-growth potential is reflected in the stock price.** The yield and 3- to 5-year total-return potential are subpar, by utility standards.

*Paul E. Debbas, CFA* *November 30, 2007*

(A) Dil. EPS. Excl. nonrec. losses: '02, 40¢; '03, 25¢; '04, 11¢; '05, 28¢; gains (losses) from disc. ops.: '03, (33¢); '04, 1¢; '05, 5¢; '06, (1¢). '06 EPS don't add due to chg. in shs. Next egs. due early Feb. (B) Div'ds historically paid early Mar., June, Sept., & Dec. Five div'ds decl. in '04. ■ Div'd reinv. plan avail. † Shareholder inv. plan avail. (C) Incl. intang.: In '06: $32.39/sh. (D) In mill. (E) Rate base: Depr. orig. cost. Rate all'd on com. eq. in NJ in '05: 9.75%; in PA in '07: 10.1%; earn. on avg. com. eq., '06: 13.5%. Regul. Climate: OH, Above Avg.; PA, NJ, Avg.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 80 |
| Earnings Predictability | 60 |

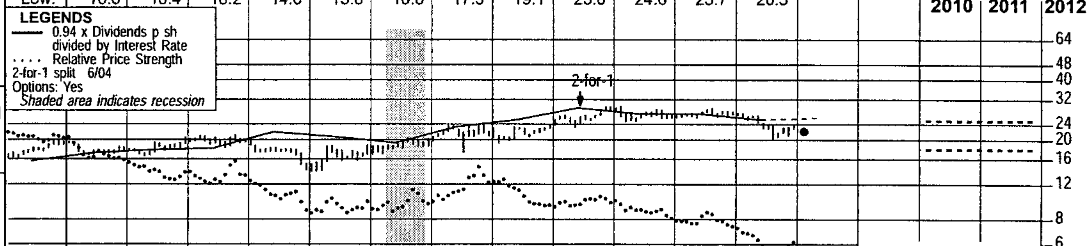
# HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE **22.08** | P/E RATIO **19.7** (Trailing: 26.9 / Median: 13.0) | RELATIVE P/E RATIO **1.23** | DIV'D YLD **5.6%** | **VALUE LINE**

**TIMELINESS** 3 Raised 1/25/08
**SAFETY** 2 Raised 2/15/02
**TECHNICAL** 3 Lowered 2/1/08
**BETA** .75 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 19.8 | 20.8 | 21.3 | 20.3 | 19.0 | 20.6 | 24.5 | 24.0 | 29.5 | 29.8 | 28.9 | 27.5 | |
| Low: | 16.6 | 16.4 | 18.2 | 14.0 | 13.8 | 16.8 | 17.3 | 19.1 | 23.0 | 24.6 | 25.7 | 20.3 | |

**Target Price Range** 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 25 | (+15%) | 8% |
| Low | 18 | (-20%) | 1% |

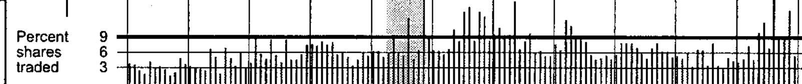
**Insider Decisions**

| | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 2 | 0 | 0 | 2 | 1 | 0 | 2 | 0 |
| Options | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 3 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 93 | 74 | 57 |
| to Sell | 68 | 83 | 89 |
| Hld's(000) | 28334 | 29301 | 26611 |

Percent shares traded




**% TOT. RETURN 12/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -11.6 | 1.3 |
| 3 yr. | -9.7 | 25.2 |
| 5 yr. | 33.2 | 117.2 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 22.71 | 20.83 | 20.64 | 20.74 | 21.76 | 22.86 | 22.95 | 23.12 | 23.64 | 26.05 | 24.26 | 22.46 | 23.49 | 23.85 | 27.36 | 30.21 | *29.95* | *31.60* | Revenues per sh | *35.75* |
| 2.37 | 2.51 | 2.23 | 2.52 | 2.73 | 2.81 | 3.01 | 3.23 | 3.35 | 3.08 | 3.33 | 3.52 | 3.54 | 3.09 | 3.22 | 3.19 | *2.85* | *3.20* | "Cash Flow" per sh | *3.75* |
| 1.20 | 1.27 | 1.19 | 1.30 | 1.33 | 1.30 | 1.38 | 1.48 | 1.45 | 1.27 | 1.60 | 1.62 | 1.58 | 1.36 | 1.46 | 1.33 | *.90* | *1.25* | Earnings per sh A | *1.50* |
| 1.11 | 1.13 | 1.15 | 1.17 | 1.19 | 1.21 | 1.22 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | *1.24* | Div'd Decl'd per sh B ■ † | *1.24* |
| 3.42 | 4.03 | 4.06 | 3.50 | 3.27 | 3.33 | 2.31 | 2.60 | 2.09 | 2.04 | 1.77 | 1.74 | 2.15 | 2.66 | 2.76 | 2.58 | *2.80* | *3.55* | Cap'l Spending per sh | *2.25* |
| 12.18 | 11.06 | 11.62 | 11.90 | 12.25 | 12.52 | 12.77 | 12.87 | 13.16 | 12.72 | 13.06 | 14.21 | 14.36 | 15.01 | 15.02 | 13.44 | *13.60* | *13.75* | Book Value per sh C | *14.25* |
| 47.73 | 49.52 | 55.35 | 57.31 | 59.55 | 61.71 | 63.79 | 64.23 | 64.43 | 65.98 | 71.20 | 73.62 | 75.84 | 80.69 | 80.98 | 81.46 | *83.50* | *85.50* | Common Shs Outst'g D | *87.00* |
| 14.2 | 15.3 | 15.5 | 12.5 | 13.5 | 13.7 | 13.2 | 13.4 | 12.1 | 12.9 | 11.8 | 13.5 | 13.8 | 19.2 | 18.3 | 20.3 | *26.6* | | Avg Ann'l P/E Ratio | *14.0* |
| .91 | .93 | .92 | .82 | .90 | .86 | .76 | .70 | .69 | .84 | .60 | .74 | .79 | 1.01 | .97 | 1.10 | *1.40* | | Relative P/E Ratio | *.95* |
| 6.5% | 5.8% | 6.2% | 7.2% | 6.6% | 6.8% | 6.7% | 6.2% | 7.1% | 7.5% | 6.6% | 5.7% | 5.7% | 4.8% | 4.6% | 4.6% | 5.2% | | Avg Ann'l Div'd Yield | *6.0%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $1331.0 mill. **Due in 5 Yrs** $320.4 mill.
**LT Debt** *$1205.0* mill. **LT Interest** *$67.0* mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 2.6x)
**Pension Assets-12/06** $875.3 mill. **Oblig.** $985.6 mill.
**Pfd Stock** $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
**Common Stock** 83,040,566 shs.
**as of 10/29/07**
**MARKET CAP: $1.8 billion (Mid Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1464.0 | 1485.2 | 1523.3 | 1719.0 | 1727.3 | 1653.7 | 1781.3 | 1924.1 | 2215.6 | 2460.9 | *2500* | *2700* | Revenues ($mill) | *3100* |
| 103.3 | 113.2 | 111.1 | 84.6 | 109.8 | 120.2 | 120.1 | 109.6 | 120.3 | 109.9 | *75.0* | *110* | Net Profit ($mill) | *140* |
| 34.9% | 33.5% | 33.9% | 41.6% | 34.6% | 34.6% | 34.9% | 45.8% | 36.4% | 36.5% | *39.0%* | *39.0%* | Income Tax Rate | *40.0%* |
| 16.5% | 14.2% | 6.1% | 9.8% | 5.9% | 4.8% | 5.1% | 7.6% | 5.9% | 8.4% | *12.0%* | *14.0%* | AFUDC % to Net Profit | *6.0%* |
| 43.4% | 44.7% | 47.2% | 58.4% | 56.9% | 52.0% | 48.6% | 47.6% | 45.2% | 49.9% | *53.0%* | *53.0%* | Long-Term Debt Ratio | *51.5%* |
| 44.0% | 43.1% | 41.4% | 39.9% | 41.6% | 46.5% | 49.8% | 51.0% | 53.3% | 48.6% | *46.0%* | *45.5%* | Common Equity Ratio | *47.0%* |
| 1851.3 | 1918.9 | 2049.5 | 2101.2 | 2235.8 | 2251.0 | 2186.9 | 2375.1 | 2283.9 | 2252.7 | *2475* | *2575* | Total Capital ($mill) | *2625* |
| 2019.6 | 2093.4 | 2066.2 | 2091.3 | 2067.5 | 2079.3 | 2311.9 | 2422.3 | 2542.8 | 2647.5 | *2720* | *2855* | Net Plant ($mill) | *2950* |
| 7.0% | 7.4% | 6.8% | 5.9% | 6.7% | 7.3% | 7.3% | 6.0% | 6.8% | 6.4% | *4.5%* | *5.5%* | Return on Total Cap'l | *6.5%* |
| 9.8% | 10.7% | 10.3% | 9.7% | 11.4% | 11.1% | 10.7% | 8.8% | 9.6% | 9.7% | *6.5%* | *9.0%* | Return on Shr. Equity | *11.0%* |
| 10.6% | 11.4% | 11.0% | 9.8% | 11.6% | 11.3% | 10.8% | 8.9% | 9.7% | 9.9% | *6.5%* | *9.0%* | Return on Com Equity E | *11.0%* |
| 3.0% | 1.8% | 1.5% | 1.7% | 4.4% | 4.3% | 3.9% | 1.1% | 1.5% | .7% | *NMF* | *Nil* | Retained to Com Eq | *2.5%* |
| 76% | 87% | 88% | 84% | 63% | 63% | 64% | 87% | 85% | 93% | *NMF* | *99%* | All Div'ds to Net Prof | *79%* |

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.9 | +.3 | +.3 |
| Avg. Indust. Use (MWH) | 6816 | 6718 | 6623 |
| Avg. Indust. Revs. per KWH (¢) | 12.86 | 15.21 | 17.38 |
| Capacity at Yearend (Mw) | 2171 | 2184 | 2204 |
| Peak Load, Winter (Mw) | 1694 | 1641 | 1685 |
| Annual Load Factor (%) | 71.5 | 74.1 | 72.5 |
| % Change Customers (yr-end) | +1.2 | +1.7 | +1.2 |
| Fixed Charge Cov. (%) | 335 | 325 | 301 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 2.0% | 2.0% | *4.5%* |
| "Cash Flow" | 1.5% | -.5% | *3.0%* |
| Earnings | .5% | -1.0% | *1.5%* |
| Dividends | .5% | -- | *Nil* |
| Book Value | 1.5% | 2.0% | *-.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 437.1 | 461.8 | 506.8 | 518.4 | 1924.1 |
| 2005 | 472.6 | 522.3 | 595.9 | 624.8 | 2215.6 |
| 2006 | 574.9 | 605.0 | 673.9 | 607.1 | 2460.9 |
| 2007 | 554.0 | 600.8 | 673.5 | *671.7* | *2500* |
| 2008 | *675* | *675* | *675* | *675* | *2700* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .40 | .14 | .51 | .31 | 1.36 |
| 2005 | .30 | .35 | .46 | .35 | 1.46 |
| 2006 | .40 | .33 | .40 | .20 | 1.33 |
| 2007 | .17 | .21 | .24 | *.28* | *.90* |
| 2008 | *.30* | *.30* | *.35* | *.30* | *1.25* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .31 | .31 | .31 | .31 | 1.24 |
| 2005 | .31 | .31 | .31 | .31 | 1.24 |
| 2006 | .31 | .31 | .31 | .31 | 1.24 |
| 2007 | .31 | .31 | .31 | .31 | 1.24 |
| 2008 | | | | | |

**BUSINESS:** Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 434,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Discontinued int'l power sub. in '01. Elec. rev. breakdown, '06: residential, 34%; commercial, 34%; large light & power, 32%. Generating sources, '06: oil, 62%; purchased, 38%. Fuel costs: 52% of revs. '06 reported depr. rate (utility): 3.9%. Has 3,400 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

**One of Hawaiian Electric Industries' utilities received an interim rate order in late December.** Maui Electric Company (MECO) was granted an interim tariff hike of $13.2 million (3.7%) based on a 10.7% return on equity. Importantly, the commission also granted MECO a regulatory mechanism to track pension costs. HEI's other two utilities, Hawaiian Electric Company (HECO) and Hawaii Electric Light Company (HELCO), have pension trackers as well.

**Despite the rate relief that HEI's utilities have received in recent years, keeping up with rising costs is tough.** And the increases in operating expenses are not only due to inflation. Maintenance and repair expenses are up because the utilities' plants have to be run harder due to a tight capacity situation. As a result, the utilities have not been earning their allowed returns on equity.

**Earnings probably didn't cover the dividend in 2007, and we think HEI will barely earn the disbursement in 2008.** Last year, third-quarter profits were especially weak because HECO received a final rate increase that was lower than an interim rate boost received in 2005. This forced the company to take an $8.3 million ($0.10 a share) reserve for a refund of previously collected revenues. In addition to the aforementioned problems at the utilities, HEI's American Savings Bank subsidiary is also experiencing difficult business conditions. The net interest margin is down, loan growth is slowing, and deposits are declining. Despite HEI's bottom-line weakness, we think the dividend will hold at the current level for the time being.

**Some large capital spending projects should be completed in the next year or two.** HECO plans to add a 110-megawatt biofuel-fired peaking unit at a cost of $164 million. The utility also plans a $69.6 million transmission project. HELCO is adding 18 mw of capacity at a cost of $92 million. This will necessitate some debt and equity financing.

**We don't recommend this stock,** despite its high yield. HEI's weak earnings are a concern, and we project no dividend growth, even over the 3- to 5-year period. Note that we have cut HEI's Financial Strength rating a notch, to B++.

*Paul E. Debbas, CFA* *February 8, 2008*

(A) Diluted EPS. Excl. gains (losses) from disc. ops.: '98, (16¢); '99, 6¢; '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due late Feb.
(B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '06: $2.45/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '07: HECO, 10.7% (interim); in '01: HELCO, 11.5%; in '07: MECO, 10.7%; earned on avg. com. eq., '06: 9.3%. Regulat. Climate: Above Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 40 |
| Earnings Predictability | 70 |

# IDACORP, INC. NYSE-IDA

| RECENT PRICE | 32.14 | P/E RATIO | 15.7 (Trailing: 15.7; Median: 15.0) | RELATIVE P/E RATIO | 0.98 | DIV'D YLD | 3.7% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 3 Raised 8/17/07
**SAFETY** 3 Lowered 2/14/03
**TECHNICAL** 2 Lowered 2/8/08
**BETA** .95 (1.00 = Market)

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 34.3 | 37.8 | 38.1 | 36.5 | 53.0 | 49.4 | 41.0 | 30.2 | 32.9 | 32.1 | 40.2 | 39.2 |
| Low: | 27.3 | 28.5 | 29.9 | 26.0 | 25.9 | 33.6 | 20.9 | 20.6 | 25.3 | 26.2 | 29.0 | 30.1 |

**Target Price Range** 2010 | 2011 | 2012

**2010-12 PROJECTIONS**

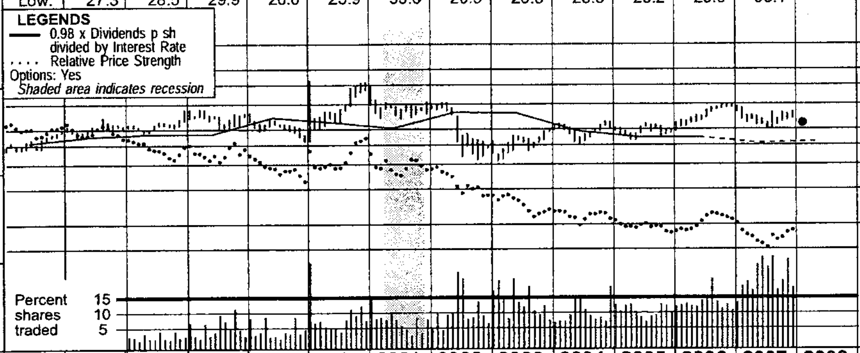
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 40 | (+25%) | 9% |
| Low | 25 | (-20%) | -2% |

**Insider Decisions**

| | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 2 | 2 | 2 | 0 | 0 | 1 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 84 | 93 | 70 |
| to Sell | 84 | 78 | 74 |
| Hld's(000) | 27777 | 34771 | 37672 |




**% TOT. RETURN 12/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -5.6 | 1.3 |
| 3 yr. | 28.6 | 25.2 |
| 5 yr. | 76.5 | 117.2 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14.22 | 13.76 | 14.57 | 14.45 | 14.51 | 15.38 | 19.90 | 29.83 | 17.50 | 27.10 | 150.10 | 24.43 | 20.41 | 20.00 | 20.15 | 21.23 | *19.80* | *21.80* | Revenues per sh | *27.80* |
| 3.26 | 3.16 | 3.53 | 3.39 | 3.89 | 4.05 | 4.22 | 4.69 | 4.50 | 5.63 | 5.63 | 4.08 | 3.50 | 4.12 | 3.87 | 4.64 | *4.25* | *4.55* | "Cash Flow" per sh | *5.25* |
| 1.56 | 1.55 | 1.97 | 1.80 | 2.10 | 2.21 | 2.32 | 2.37 | 2.43 | 3.50 | 3.35 | 1.63 | .96 | 1.90 | 1.75 | 2.35 | *2.00* | *2.15* | Earnings per sh A | *2.25* |
| 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.70 | 1.20 | 1.20 | 1.20 | *1.20* | Div'd Decl'd per sh B† ■ | *1.20* |
| 3.94 | 3.26 | 3.32 | 2.94 | 2.23 | 2.49 | 2.51 | 2.37 | 2.95 | 3.73 | 4.78 | 3.53 | 3.89 | 4.73 | 4.53 | 5.16 | *6.80* | *6.15* | Cap'l Spending per sh | *5.25* |
| 17.06 | 17.28 | 17.86 | 17.91 | 18.15 | 18.47 | 18.93 | 19.42 | 20.02 | 21.82 | 23.15 | 23.01 | 22.54 | 23.88 | 24.04 | 25.76 | *26.05* | *27.75* | Book Value per sh C | *30.95* |
| 33.98 | 36.19 | 37.09 | 37.61 | 37.61 | 37.61 | 37.61 | 37.61 | 37.61 | 37.61 | 37.63 | 38.02 | 38.34 | 42.22 | 42.66 | 43.63 | *45.00* | *46.30* | Common Shs Outst'g D | *47.50* |
| 16.8 | 17.0 | 15.4 | 13.9 | 12.4 | 13.7 | 13.6 | 14.4 | 12.7 | 10.9 | 11.4 | 18.9 | 26.5 | 15.5 | 16.7 | 15.1 | *16.1* | | Avg Ann'l P/E Ratio | *14.5* |
| 1.07 | 1.03 | .91 | .91 | .83 | .86 | .78 | .75 | .72 | .71 | .58 | 1.03 | 1.51 | .82 | .89 | .82 | *.85* | | Relative P/E Ratio | *.95* |
| 7.1% | 7.1% | 6.1% | 7.4% | 7.2% | 6.1% | 5.9% | 5.4% | 6.0% | 4.9% | 4.9% | 6.0% | 6.7% | 4.1% | 4.1% | 3.4% | 3.7% | | Avg Ann'l Div'd Yield | *3.6%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $1298.5 mill. **Due in 5 Yrs** $460.7 mill.
**LT Debt** $1061.3 mill. **LT Interest** $57.2 mill.
(LT interest earned: 2.6x)

**Pension Assets-12/06** $400.9 mill. **Oblig.** $425.6 mill.

**Pfd Stock** None

**Common Stock** 44,995,330 shs.

**MARKET CAP: $1.6 billion (Mid Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 748.5 | 1122.0 | 658.3 | 1019.4 | 5648.0 | 928.8 | 782.7 | 844.5 | 859.5 | 926.3 | *890* | *1010* | Revenues ($mill) | *1320* |
| 92.3 | 94.8 | 96.9 | 137.6 | 130.0 | 66.3 | 40.1 | 77.8 | 63.7 | 100.1 | *88.0* | *97.0* | Net Profit ($mill) | *105* |
| 33.5% | 32.0% | 32.0% | 32.1% | 33.3% | -- | -- | -- | 16.9% | 13.3% | *32.0%* | *32.0%* | Income Tax Rate | *32.0%* |
| .6% | 1.3% | 3.2% | 3.6% | 3.1% | 3.0% | 7.5% | 3.9% | 4.7% | 4.0% | *5.0%* | *5.0%* | AFUDC % to Net Profit | *5.0%* |
| 46.2% | 49.4% | 48.9% | 48.3% | 46.4% | 49.2% | 50.8% | 49.3% | 50.0% | 45.2% | *47.5%* | *47.5%* | Long-Term Debt Ratio | *50.0%* |
| 46.8% | 44.2% | 44.8% | 45.9% | 47.9% | 47.9% | 46.4% | 50.7% | 50.0% | 54.8% | *52.5%* | *52.5%* | Common Equity Ratio | *50.0%* |
| 1522.2 | 1652.3 | 1680.3 | 1790.0 | 1818.0 | 1826.9 | 1862.5 | 1987.8 | 2048.8 | 2052.8 | *2245* | *2455* | Total Capital ($mill) | *2940* |
| 1716.9 | 1711.5 | 1745.7 | 1805.0 | 1886.0 | 1906.5 | 2088.3 | 2209.5 | 2314.3 | 2419.1 | *2620* | *2795* | Net Plant ($mill) | *3175* |
| 7.8% | 7.3% | 7.4% | 9.2% | 8.7% | 5.1% | 3.7% | 5.3% | 4.5% | 6.2% | *5.5%* | *5.5%* | Return on Total Cap'l | *5.0%* |
| 11.3% | 11.3% | 11.3% | 14.9% | 13.3% | 7.1% | 4.4% | 7.7% | 6.2% | 8.9% | *7.5%* | *7.5%* | Return on Shr. Equity | *7.0%* |
| 12.2% | 12.2% | 12.1% | 16.0% | 14.4% | 7.0% | 4.2% | 7.2% | 6.2% | 8.9% | *7.5%* | *7.5%* | Return on Com Equity E | *7.0%* |
| 2.4% | 2.6% | 2.9% | 7.5% | 6.3% | NMF | NMF | 2.7% | 1.3% | 4.3% | *3.0%* | *3.5%* | Retained to Com Eq | *3.5%* |
| 82% | 80% | 78% | 55% | 58% | 113% | NMF | 65% | 80% | 51% | *60%* | *56%* | All Div'ds to Net Prof | *53%* |

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.0 | -- | +1.0 |
| Avg. Indust. Use (MWH) | 26548 | 26535 | 26731 |
| Avg. Indust. Revs. per KWH (¢) | 3.35 | 3.45 | 2.96 |
| Capacity at Peak (Mw) | 2912 | 3084 | 3085 |
| Peak Load, Summer (Mw) | 2843 | 2963 | 3084 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +3.2 | +3.8 | +3.6 |
| Fixed Charge Cov. (%) | 148 | 207 | 274 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 3.5% | -20.5% | *5.0%* |
| "Cash Flow" | 1.0% | -4.5% | *4.0%* |
| Earnings | -- | -8.5% | *2.0%* |
| Dividends | -4.5% | -8.5% | *Nil* |
| Book Value | 3.0% | 2.5% | *4.0%* |

| Cal-endar | QUARTERLY REVENUES($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 188.2 | 211.9 | 246.7 | 197.7 | 844.5 |
| 2005 | 195.6 | 204.9 | 248.4 | 210.6 | 859.5 |
| 2006 | 268.4 | 242.6 | 230.5 | 184.8 | 926.3 |
| 2007 | 206.7 | 213.8 | 261.5 | *208.0* | *890* |
| 2008 | *235* | *260* | *270* | *245* | *1010* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .51 | .34 | .68 | .37 | 1.90 |
| 2005 | .55 | .22 | .56 | .42 | 1.75 |
| 2006 | .64 | .53 | .76 | .42 | 2.35 |
| 2007 | .56 | .42 | .65 | *.37* | *2.00* |
| 2008 | *.60* | *.43* | *.75* | *.37* | *2.15* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B† ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .465 | .465 | .465 | .30 | 1.70 |
| 2005 | .30 | .30 | .30 | .30 | 1.20 |
| 2006 | .30 | .30 | .30 | .30 | 1.20 |
| 2007 | .30 | .30 | .30 | .30 | 1.20 |
| 2008 | | | | | |

**BUSINESS:** IDACORP, Inc. is the holding company for Idaho Power, a utility that owns 17 hydroelectric generation developments and partly owns three coal plants. Sold a patented fuel cell system in 2006. Sells electricity in Idaho (96% of revenues.) and Oregon (4%). Revenue breakdown: residential, 33%; commercial, 18%; industrial, 11%; other, 38%. Fuel and purchased power cost: 43% of '06 revenues; estimated labor costs: 9.0%. 2006 depreciation rate: 2.8%. Fuel sources: hydro, 43%; thermal, 33%; purchases, 24%. Has 1,976 employees. Chairman: Jon H. Miller. Chief Executive Officer & President: J. LaMont Kean. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

**IDACORP's construction budget will be large for the next few years.** To cover an expected 2% annual rise in customer energy demand, IDA issued a 10-year resource plan that calls for an increase of 2,350 megawatts (mw) in generation and 285 mw of new transmission lines over the next 18 years. For starters, it has bought 13 (mw) of geothermal power and has contracts to purchase 100 mw of wind-driven power that will go on line by year-end 2008. To diversify the energy mix, it will build a 170-mw gas-fired unit at the Evander Andrews site with a transmission line to carry the power where needed. On the hydro side, Shoshone Falls' capacity will be boosted from 12.5 mw to 62.5 mw, if water is available. New coal plants outside of Idaho are under consideration. The package will require capital spending of about $380 million annually through 2009 and lesser amounts thereafter.

**The company has filed for higher rates.** Since the last rate case, IDA has invested large sums in its electric superstructure. These expenditures include some $200 million on 650 miles of transmission and distribution lines and 10 new substations. Another $127 million was spent on maintenance and improvement of existing facilities and on environmental upgrading at coal- and gas-fired plants. Too, costs of $34 million have been incurred for relicensing hydroelectric units. All told, the utility seeks a hike of $63.9 million, based on an 11.50% return on equity, up from the present 10.25%. A regulatory order on the request is due by late February. It will take effect when issued.

**We look for improved earnings in 2008.** Last year's results were hurt by poor hydro conditions. This increased O&M expenses and raised the need for more costly fossil fuel generation. Our 2008 earnings estimate of $2.15 a share assumes a return to average winter snowpack and a reasonable rate award. Slow, but steady, gains are likely to 2010-2012.

**Dividend growth is not the company's strong suit.** Though the yield is fractionally above the industry norm, we expect no increase in the payout for a while, because of the need to save cash for the building program. Income-oriented investors will likely fare better elsewhere.

*Arthur H. Medalie* *February 8, 2008*

(A) EPS diluted. Excl. nonrecurring gains (loss): '93, 16¢; '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in late Feb., late May, late Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '06: $9.65/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '04: 10.25%; earned on avg. system com. eq., '06: 9.3%. Regulatory Climate: Above Average.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 15 |
| Earnings Predictability | 50 |

# MGE ENERGY INC. NDQ-MGEE

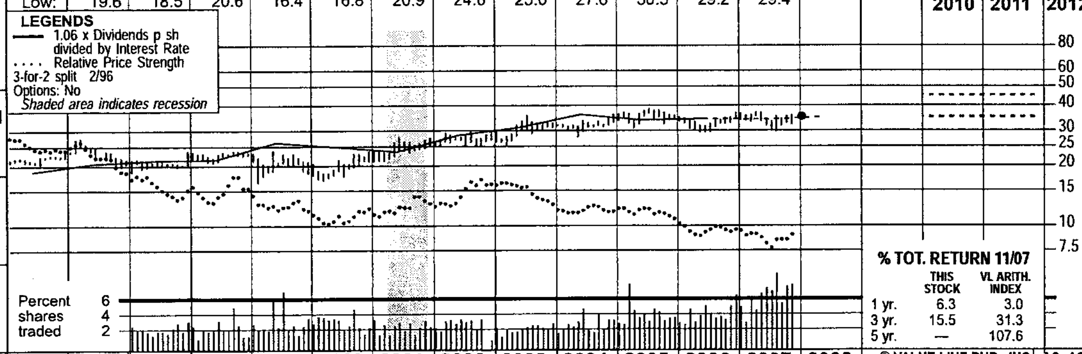
RECENT PRICE **35.24** | P/E RATIO **14.8** (Trailing: 15.3; Median: 16.0) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **4.0%** | VALUE LINE

**TIMELINESS** 3 Raised 8/17/07
**SAFETY** 1 New 1/3/03
**TECHNICAL** 3 Raised 11/30/07
**BETA** .95 (1.00 = Market)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 27.5 | 23.8 | 23.8 | 23.9 | 23.7 | 27.8 | 30.1 | 35.8 | 36.4 | 38.8 | 37.0 | 
| Low: | 19.6 | 18.5 | 20.6 | 16.4 | 16.8 | 20.9 | 24.6 | 25.0 | 27.6 | 30.5 | 29.2 |

| High: | 27.5 | 23.8 | 23.8 | 23.9 | 23.7 | 27.8 | 30.1 | 35.8 | 36.4 | 38.8 | 37.0 | 37.0 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Low: | 19.6 | 18.5 | 20.6 | 16.4 | 16.8 | 20.9 | 24.6 | 25.0 | 27.6 | 30.5 | 29.2 | 29.4 |

**Target Price Range** 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 45 | (+30%) | 10% |
| Low | 35 | (Nil) | 4% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 49 | 38 | 44 |
| to Sell | 16 | 33 | 30 |
| Hld's(000) | 6829 | 7891 | 7907 |

**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 6.3 | 3.0 |
| 3 yr. | 15.5 | 31.3 |
| 5 yr. | — | 107.6 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14.47 | 14.21 | 15.18 | 15.23 | 15.46 | 15.75 | 16.46 | 15.53 | 16.96 | 19.50 | 19.55 | 19.75 | 21.89 | 20.84 | 25.10 | 24.20 | **24.65** | **25.10** | Revenues per sh | **26.50** |
| 2.83 | 2.79 | 2.86 | 2.92 | 3.03 | 2.41 | 3.26 | 3.59 | 3.81 | 3.89 | 3.78 | 3.33 | 2.94 | 2.88 | 3.00 | 3.52 | **3.50** | **3.55** | "Cash Flow" per sh | **4.10** |
| 1.52 | 1.45 | 1.51 | 1.53 | 1.49 | .82 | 1.40 | 1.38 | 1.48 | 1.67 | 1.62 | 1.69 | 1.71 | 1.77 | 1.57 | 2.06 | **2.35** | **2.40** | Earnings per sh A | **2.60** |
| 1.17 | 1.19 | 1.19 | 1.25 | 1.26 | 1.28 | 1.29 | 1.30 | 1.31 | 1.32 | 1.33 | 1.34 | 1.35 | 1.36 | 1.37 | 1.39 | **1.41** | **1.43** | Div'd Decl'd per sh B ■ | **1.50** |
| 1.24 | .77 | 1.47 | 1.64 | 1.19 | 1.36 | 1.35 | 1.92 | 3.16 | 4.44 | 2.47 | 4.45 | 4.52 | 4.70 | 4.19 | 4.41 | **4.00** | **4.00** | Cap'l Spending per sh | **4.00** |
| 10.98 | 11.24 | 11.51 | 11.78 | 12.01 | 11.14 | 11.25 | 11.34 | 11.49 | 12.05 | 12.67 | 12.94 | 14.34 | 16.59 | 16.81 | 17.89 | **17.00** | **17.90** | Book Value per sh | **18.70** |
| 16.05 | 16.05 | 16.08 | 16.08 | 16.08 | 16.08 | 16.08 | 16.08 | 16.16 | 16.62 | 17.07 | 17.57 | 18.34 | 20.39 | 20.45 | 20.98 | **21.90** | **21.90** | Common Shs Outst'g C | **21.90** |
| 11.3 | 14.3 | 15.2 | 14.3 | 14.5 | 28.1 | 14.5 | 16.2 | 14.0 | 11.7 | 14.8 | 16.0 | 17.5 | 18.0 | 22.4 | 15.9 | *Bold figures are* | | Avg Ann'l P/E Ratio | **15.0** |
| .72 | .87 | .90 | .94 | .97 | 1.76 | .84 | .84 | .80 | .76 | .76 | .87 | 1.00 | .95 | 1.19 | .86 | *Value Line* | | Relative P/E Ratio | **1.00** |
| 6.8% | 5.7% | 5.2% | 5.7% | 5.8% | 5.5% | 6.3% | 5.8% | 6.3% | 6.7% | 5.5% | 5.0% | 4.5% | 4.3% | 3.9% | 4.3% | *estimates* | | Avg Ann'l Div'd Yield | **4.6%** |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $336.3 mill. **Due in 5 Yrs** $65.0 mill.
**LT Debt** $232.3 mill. **LT Interest** $12.0 mill.
(LT interest earned: 4.3x)

**Leases, Uncapitalized** Annual rentals $1.4 mill.
**Pension Assets-12/05** $116.7 mill.
**Obligation** $173.5 mill.

**Pfd Stock** None

**Common Stock** 21,868,684 shs.
as of 10/31/07
**MARKET CAP: $725 million (Small Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 264.7 | 249.8 | 274.0 | 324.1 | 333.7 | 347.1 | 401.5 | 424.9 | 513.4 | 507.5 | **540** | **550** | Revenues ($mill) | **580** |
| 22.5 | 22.2 | 23.8 | 27.4 | 27.2 | 29.2 | 30.6 | 33.8 | 32.1 | 42.4 | **51.0** | **53.0** | Net Profit ($mill) | **58.0** |
| 37.5% | 37.1% | 36.9% | 36.5% | 36.9% | 39.1% | 39.4% | 37.9% | 38.2% | 37.9% | **38.0%** | **38.0%** | Income Tax Rate | **38.0%** |
| .2% | .9% | 1.9% | 1.9% | 2.2% | -- | -- | -- | 2.2% | 1.7% | **2.0%** | **2.0%** | AFUDC % to Net Profit | **2.0%** |
| 41.8% | 46.7% | 44.5% | 47.8% | 42.2% | 45.8% | 43.5% | 37.4% | 39.3% | 38.7% | **39.5%** | **39.0%** | Long-Term Debt Ratio | **39.0%** |
| 58.2% | 53.3% | 55.5% | 52.2% | 57.8% | 54.2% | 56.5% | 62.6% | 60.7% | 61.3% | **60.5%** | **61.0%** | Common Equity Ratio | **61.0%** |
| 310.8 | 342.0 | 334.3 | 383.7 | 373.9 | 419.5 | 465.3 | 540.5 | 566.2 | 612.6 | **620** | **640** | Total Capital ($mill) | **670** |
| 284.7 | 258.6 | 260.1 | 342.8 | 401.2 | 451.5 | 537.5 | 607.4 | 667.7 | 728.4 | **680** | **690** | Net Plant ($mill) | **700** |
| 8.8% | 8.0% | 8.8% | 8.8% | 9.0% | 8.1% | 7.8% | 7.1% | 6.6% | 7.8% | **9.0%** | **9.5%** | Return on Total Cap'l | **9.5%** |
| 12.4% | 12.2% | 12.8% | 13.7% | 12.6% | 12.8% | 11.6% | 10.0% | 9.3% | 11.3% | **12.5%** | **13.5%** | Return on Shr. Equity | **14.0%** |
| 12.4% | 12.2% | 12.8% | 13.7% | 12.6% | 12.8% | 11.6% | 10.0% | 9.3% | 11.3% | **12.5%** | **13.5%** | Return on Com Equity D | **14.0%** |
| 1.0% | .7% | 1.5% | 2.9% | 2.3% | 2.6% | 2.5% | 2.3% | 1.2% | 3.7% | **5.0%** | **5.5%** | Retained to Com Eq | **6.0%** |
| 92% | 94% | 89% | 79% | 82% | 79% | 79% | 77% | 87% | 67% | **61%** | **59%** | All Div'ds to Net Prof | **57%** |

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +1.6 | -0.7 | -0.7 |
| Avg. Indust. Use (MWH) | 4624 | 3023 | 2865 |
| Avg. Indust. Revs. per KWH (¢) | 4.40 | 5.42 | 6.20 |
| Capacity at Peak (Mw) | 763 | 812 | 780 |
| Peak Load, Summer (Mw) | 714 | 690 | NA |
| Annual Load Factor (%) | 59.1 | 48.1 | NA |
| % Change Customers (avg.) | +1.0 | +1.6 | NA |
| Fixed Charge Cov. (%) | 388 | 352 | 340 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 4.0% | 4.5% | .5% |
| "Cash Flow" | 1.0% | -4.0% | .5% |
| Earnings | 3.5% | 2.5% | 6.0% |
| Dividends | 1.0% | 1.0% | .5% |
| Book Value | 4.0% | 7.0% | 7.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 135.4 | 85.4 | 86.8 | 117.3 | 424.9 |
| 2005 | 138.9 | 100.5 | 114.4 | 159.6 | 513.4 |
| 2006 | 158.6 | 99.7 | 110.6 | 138.6 | 507.5 |
| 2007 | 167.9 | 110.5 | 116.3 | **145.3** | **540** |
| 2008 | **171** | **113** | **118** | **148** | **550** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .74 | .30 | .48 | .25 | 1.77 |
| 2005 | .40 | .27 | .48 | .42 | 1.57 |
| 2006 | .56 | .34 | .62 | .54 | 2.06 |
| 2007 | .59 | .47 | .71 | **.58** | **2.35** |
| 2008 | **.60** | **.49** | **.71** | **.60** | **2.40** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .336 | .336 | .338 | .338 | 1.35 |
| 2004 | .338 | .338 | .342 | .342 | 1.36 |
| 2005 | .342 | .342 | .345 | .345 | 1.37 |
| 2006 | .345 | .345 | .348 | .348 | 1.39 |
| 2007 | .348 | .348 | .355 | .355 | |

**BUSINESS:** MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to nearly 132,000 customers in a 250-square-mile area of Dane County and gas service to 129,000 customers in 1,375 square miles in seven counties in Wisconsin. Electric revenue breakdown, '06: residential, 34%; commercial, 52%; industrial, 6%; public authorities and other, 7%. Generating sources, '06: coal, 49%; purchased power, 44%; natural gas and other, 7%. Fuel costs: 43% of revenues. '06 reported depreciation rate: electric, 3.4%; gas, 3.3%. Has 750 employees. Chairman, President & CEO: Gary J. Wolter. Inc.: Wisconsin. Address: 133 South Blair St., P.O. Box 1231, Madison, WI 53701-1231. Telephone: 608-252-7000. Internet: www.mge.com.

**MGE Energy should report its 2007 results sometime in late February.** We look for share net to increase 14% over the $2.06 that the Wisconsin-based electric and gas utility earned in 2006. Revenues, meanwhile, ought to come in at $540 million, some 6% higher on the year. Strong residential power demand will no doubt be a key driver. So, too, should increased power "sales for resale", coinciding with MGE's involvement in the MISO and PJM regional transmission organizations.

**We look for MGE to build on its success in 2008 and out to 2010-2012.** Importantly, the utility should continue to benefit from favorable demographics within its Dane County service area. Strong commercial and residential development in and around the city of Madison, in particular, should boost power demand. Madison is home to a major campus in the state university system, and its outlying population is growing fast.

**MGE should soon finish construction on a new wind farm in north-central Iowa.** The $59 million project reached a major milestone in October when the first giant turbine towers were erected on site. Upon completion, the 18-turbine, 30-megawatt wind farm should generate enough electricity to meet the annual power needs of some 12,000 homes. The project, along with other renewable energy commitments, is allowing MGE to increase its wind capacity by nearly eight times, to 86 megawatts. Importantly, the new wind farm will help provide energy for an expanded "green" pricing program slated for launch early in 2008. As part of MGE's Green Power Tomorrow program, customers can pay a premium to add more renewable energy to their mix.

**MGE Energy shares may appeal to income investors.** The dividend yield, at 4.0%, is nicely above the *Value Line* average. What's more, additional dividend hikes are likely, given the utility's good earnings prospects and its enviable record of payout increases (30-plus years and counting). At the current quotation, the stock is trading just within our 3- to 5-year Target Price Range. However, the prospect of lower interest rates should lead to an adjustment in risk-adjusted yields, which ought to support the stock price.

*Nils C. Van Liew* *December 28, 2007*

(A) Excl. nonrecurring loss: '96, 42¢. Next earnings report due late Feb. (B) Dividends historically paid in mid-March, June, September, December. ■ Dvd. reinvestment plan available. (C) In millions, adjusted for stock split. (D) Rate allowed on common equity in '02: 12.9%; earned on average common equity, '02: 13.0%. Regulatory Climate: Above Average.

| | |
|---|---|
| **Company's Financial Strength** | A |
| **Stock's Price Stability** | 85 |
| **Price Growth Persistence** | 50 |
| **Earnings Predictability** | 75 |

# NISOURCE INC. NYSE-NI

RECENT PRICE 18.56 | P/E RATIO 16.4 (Trailing: 15.1 Median: 16.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 3 Lowered 6/8/07

SAFETY 3 Lowered 1/4/02

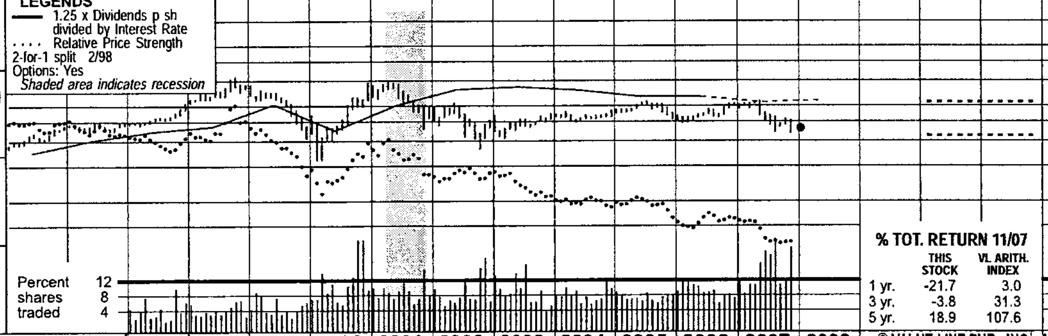
TECHNICAL 3 Raised 12/28/07

BETA .90 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 20.1 | 24.9 | 33.8 | 30.9 | 31.5 | 32.6 | 25.0 | 22.0 | 22.8 | 25.5 | 24.8 | 25.4 |
| Low: | 17.6 | 19.0 | 24.7 | 16.4 | 12.8 | 18.3 | 14.5 | 16.4 | 19.7 | 20.4 | 19.5 | 17.5 |

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 2/98
Options: Yes
Shaded area indicates recession



**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 25 | (+35%) | 11% |
| Low | 17 | (-10%) | 3% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 163 | 176 | 136 |
| to Sell | 149 | 142 | 179 |
| Hld's(000) | 202459 | 215399 | 209234 |

Percent shares traded 12 8 4

% TOT. RETURN 11/07

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -21.7 | 3.0 |
| 3 yr. | -3.8 | 31.3 |
| 5 yr. | 18.9 | 107.6 |

NiSource acquired Columbia Energy on November 1, 2000, paying approximately $6 billion in cash and stock. Columbia shareholders who chose cash received $70 a share, plus a security with a face value of $2.60. Those who chose stock received $74 a share in NiSource common stock. Shareholders' selections were prorated to reflect a 30% stock portion of the transaction. In 2003, NiSource sold Columbia's exploration and production business.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20.81 | 24.95 | 25.33 | 29.34 | 45.59 | 26.09 | 23.78 | 24.63 | 28.97 | 27.37 | 28.40 | 29.75 | Revenues per sh | 33.75 |
| 3.54 | 3.83 | 3.80 | 2.74 | 4.23 | 3.94 | 3.47 | 3.47 | 3.08 | 3.20 | 3.30 | 3.40 | "Cash Flow" per sh | 4.00 |
| 1.54 | 1.59 | 1.27 | 1.39 | 1.13 | 1.91 | 1.59 | 1.62 | 1.08 | 1.14 | 1.20 | 1.25 | Earnings per sh A | 1.50 |
| .92 | .98 | 1.04 | .81 | 1.16 | 1.16 | 1.10 | .92 | .92 | .92 | .92 | .92 | Div'd Decl'd per sh B ■ | 1.00 |
| 1.76 | 2.09 | 2.75 | 1.80 | 3.22 | 2.50 | 2.19 | 1.91 | 2.17 | 2.33 | 2.90 | 2.90 | Cap'l Spending per sh | 3.00 |
| 10.17 | 9.78 | 10.90 | 16.61 | 16.72 | 16.78 | 16.81 | 17.69 | 18.09 | 18.32 | 18.60 | 18.90 | Book Value per sh C | 20.25 |
| 124.31 | 117.53 | 124.14 | 205.55 | 207.49 | 248.86 | 262.63 | 270.63 | 272.62 | 273.65 | 274.75 | 275.50 | Common Shs Outst'g D | 277.00 |
| 13.6 | 17.7 | 19.6 | 14.9 | 23.4 | 10.8 | 12.2 | 13.0 | 21.4 | 19.2 | Bold figures are | | Avg Ann'l P/E Ratio | 14.0 |
| .78 | .92 | 1.12 | .97 | 1.20 | .59 | .70 | .69 | 1.14 | 1.04 | Value Line | | Relative P/E Ratio | .95 |
| 4.4% | 3.5% | 4.2% | 3.9% | 4.4% | 5.6% | 5.7% | 4.4% | 4.0% | 4.2% | estimates | | Avg Ann'l Div'd Yield | 4.8% |
| 2586.5 | 2932.8 | 3144.6 | 6030.7 | 9458.7 | 6492.3 | 6246.6 | 6666.2 | 7899.1 | 7490.0 | 7800 | 8200 | Revenues ($mill) | 9375 |
| 199.5 | 202.4 | 168.7 | 196.9 | 243.5 | 412.5 | 419.4 | 434.6 | 298.7 | 314.6 | 335 | 345 | Net Profit ($mill) | 420 |
| 34.7% | 33.3% | 34.9% | 33.3% | 44.7% | 35.5% | 35.3% | 35.7% | 33.3% | 35.2% | 37.0% | 37.0% | Income Tax Rate | 37.0% |
| .2% | 1.8% | 3.4% | 2.0% | 1.8% | .6% | .6% | .5% | 1.1% | 3.5% | 4.0% | 3.0% | AFUDC % to Net Profit | 2.0% |
| 54.2% | 56.4% | 51.8% | 63.4% | 63.3% | 55.7% | 57.1% | 49.8% | 51.2% | 50.7% | 54.0% | 53.0% | Long-Term Debt Ratio | 51.0% |
| 41.1% | 38.8% | 35.5% | 35.2% | 35.8% | 43.4% | 42.1% | 49.3% | 48.0% | 49.3% | 46.0% | 47.0% | Common Equity Ratio | 49.0% |
| 3077.2 | 2959.7 | 3813.3 | 9695.6 | 9683.8 | 9622.8 | 10490 | 9704.1 | 10285 | 10160 | 11060 | 11110 | Total Capital ($mill) | 11525 |
| 3656.1 | 3662.1 | 5230.4 | 9546.7 | 9554.7 | 10068 | 9304.9 | 9384.7 | 9554.3 | 9694.5 | 9935 | 10160 | Net Plant ($mill) | 10700 |
| 8.2% | 8.7% | 6.0% | 2.7% | 4.7% | 6.7% | 6.0% | 6.4% | 4.8% | 4.8% | 4.5% | 5.0% | Return on Total Cap'l | 5.5% |
| 14.2% | 15.7% | 9.2% | 5.5% | 6.8% | 9.7% | 9.3% | 8.9% | 6.0% | 6.3% | 6.5% | 6.5% | Return on Shr. Equity | 7.5% |
| 15.1% | 16.9% | 11.9% | 5.5% | 6.8% | 9.7% | 9.4% | 9.0% | 6.0% | 6.3% | 6.5% | 6.5% | Return on Com Equity E | 7.5% |
| 6.3% | 6.7% | 2.6% | 1.7% | NMF | 3.9% | 3.0% | 3.9% | .9% | 1.2% | 1.5% | 2.0% | Retained to Com Eq | 2.5% |
| 60% | 62% | 79% | 71% | 101% | 60% | 69% | 57% | 85% | 80% | 76% | 73% | All Div'ds to Net Prof | 66% |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $6657.3 mill. **Due in 5 Yrs** $2563.1 mill.
**LT Debt** $5923.4 mill. **LT Interest** $374.0 mill.
(LT interest earned: 2.5x)

**Leases, Uncapitalized** Annual rentals $47.2 mill.
**Pension Assets-12/06** $2.05 bill. **Oblig.** $2.29 bill.

**Pfd Stock** None

**Common Stock** 274,171,749 shs. as of 10/31/07

**MARKET CAP: $5.1 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.4 | +2.9 | +.7 |
| Avg. Indust. Use (MWH) | 3672 | 3621 | 3783 |
| Avg. Indust. Revs. per KWH (¢) | 4.45 | 4.87 | 5.40 |
| Capacity at Peak (Mw) | 3297 | 3560 | 3313 |
| Peak Load, Summer (Mw) | 2922 | 3166 | 3238 |
| Annual Load Factor (%) | 66.0 | 62.8 | 61.5 |
| % Change Customers (yr-end) | +1.2 | +1.0 | +.7 |
| Fixed Charge Cov. (%) | 258 | 223 | 223 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 6.5% | -4.0% | 4.0% |
| "Cash Flow" | .5% | -2.0% | 3.5% |
| Earnings | -.5% | .5% | 2.5% |
| Dividends | 1.5% | -1.5% | 1.5% |
| Book Value | 7.5% | 4.0% | 2.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 2473 | 1245 | 980 | 1968 | 6666.2 |
| 2005 | 2683 | 1356 | 1165 | 2695 | 7899.1 |
| 2006 | 2972 | 1312 | 1156 | 2050 | 7490.0 |
| 2007 | 2894 | 1577 | 1241 | 2088 | 7800 |
| 2008 | 3050 | 1650 | 1300 | 2200 | 8200 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .82 | .13 | .08 | .58 | 1.62 |
| 2005 | .77 | .07 | d.02 | .27 | 1.08 |
| 2006 | .63 | .08 | .10 | .33 | 1.14 |
| 2007 | .76 | .11 | .03 | .30 | 1.20 |
| 2008 | .75 | .05 | .05 | .40 | 1.25 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .29 | .29 | .29 | .23 | 1.10 |
| 2004 | .23 | .23 | .23 | .23 | .92 |
| 2005 | .23 | .23 | .23 | .23 | .92 |
| 2006 | .23 | .23 | .23 | .23 | .92 |
| 2007 | .23 | .23 | .23 | .23 | |

**BUSINESS:** NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 454,000 electric in IN, 3.3 million gas in IN, OH, PA, KY, VA, MD, MA, NH, ME. Acquired IWC Resources 3/97; Bay State Gas 2/99; Columbia Energy 11/00. Electric rev. breakdown, '06: residential, 28%; commercial, 28%; industrial, 39%; other, 5%. Generating sources, '06: coal, 81%; purchased & other, 19%. Fuel costs: 58% of revs. '06 reported deprec. rates: 3.6% electric, 2.8% gas. Has 7,400 employees. Chairman: Ian M. Rolland. President & CEO: Robert C. Skaggs, Jr. Inc.: Indiana. Address: 801 East 86th Ave., Merrillville, Indiana 46410. Tel.: 877-647-5990. Internet: www.nisource.com.

**We have lowered our 2007 and 2008 earnings estimates for NiSource.** In the third quarter, the company took a charge of $16.2 million ($0.06 a share) for a rate refund associated with a regulatory settlement related to Northern Indiana Public Service's purchased-power costs. The settlement will also affect ongoing earnings. Accordingly, we have cut our 2007 and 2008 share-earnings estimates by $0.15 and $0.10, respectively. NiSource stock continues to languish, having fallen more than 20% since the start of 2007.

**NiSource's outsourcing agreement with IBM didn't meet expectations.** Many of the functions that were outsourced will be brought back in house because things didn't go smoothly. The company stated that the expected cost savings will not be achieved, even though the 10-year contract still has 7.5 years remaining.

**The company has received two rate orders, and more rate cases are coming up in 2008.** Columbia Gas of Kentucky was granted a tariff hike of $7.25 million, based on a 10.5% return on equity. A $5.9 million increase for Bay State Gas in Massachusetts took effect on November 1st. Bay State is seeking an additional $7.5 million. In early 2008, Columbia Gas plans to file rate applications in Pennsylvania and Ohio. By mid-2008, NIPSCO must file an electric case in Indiana. The utility is seeking to acquire 1,060 megawatts of gas-fired capacity—including the 525-mw Whiting plant, which is now a nonregulated (and money-losing) asset owned by NiSource. This will be reflected in the upcoming rate case.

**NiSource is evaluating the possibility of placing some of its midstream gas assets in a master limited partnership** (MLP). This would lower the cost of capital for this operation. NiSource is already building gas infrastructure to serve the Northeast, and the possibility of additional projects exists.

**We don't recommend this equity, despite its above-average yield.** Even the announcement of an MLP likely wouldn't be enough to push the stock upward. The modest earnings and dividend growth we project through 2010-2012 suggests that total-return potential over that timeframe isn't impressive.

*Paul E. Debbas, CFA* *December 28, 2007*

(A) Diluted EPS. Excl. nonrec. gains (losses): '00, 24¢; '01, (10¢); '02, 9¢; '03, 1¢ net; '05, (4¢); gains (losses) on disc. ops.: '00, 7¢; '02, (25¢); '03, ($1.27); '04, 2¢; '05, 10¢; '06, (11¢); '07, 3¢. '04 & '05 EPS don't add due to rounding. Next egs. due late Jan. (B) Div'ds historically paid in mid-Feb., May, Aug., Nov. There were only 3 declarations in '00. ■ Div'd reinv. avail. (C) Incl. intang. In '06: $19.77/sh. (D) In mill., adj. for split. (E) Rate base: Fair val. Rate all'd on com. eq. in '87: 13.5%; earned on avg. com. eq., '06: 6.2%. Reg. Climate: Above Avg.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 10 |
| Earnings Predictability | 65 |

# NSTAR NYSE-NST

| RECENT PRICE | 34.70 | P/E RATIO | 15.9 (Trailing: 16.6 / Median: 14.0) | RELATIVE P/E RATIO | 0.95 | DIV'D YLD | 4.1% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 4 Lowered 12/8/06

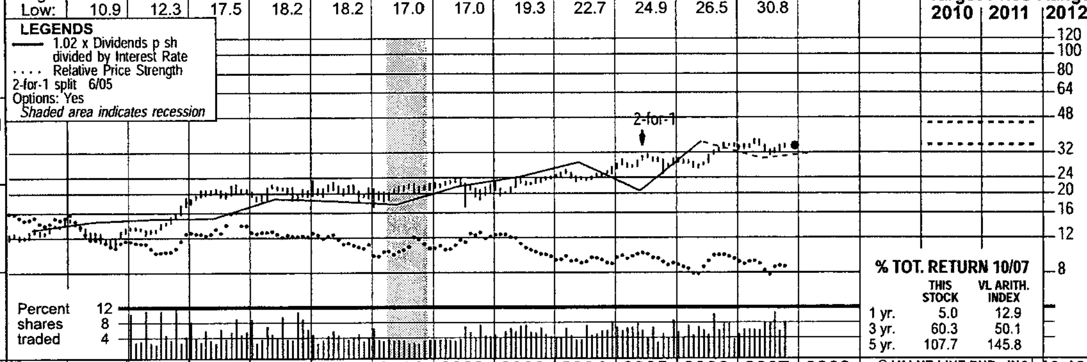
**SAFETY** 1 Raised 6/11/99

**TECHNICAL** 3 Raised 7/6/07

**BETA** .75 (1.00 = Market)

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 15.1 | 19.2 | 22.5 | 22.3 | 23.5 | 22.6 | 24.1 | 24.5 | 27.2 | 31.5 | 35.9 | 37.4 |
| Low: | 10.9 | 12.3 | 17.5 | 18.2 | 18.2 | 17.0 | 17.0 | 19.3 | 22.7 | 24.9 | 26.5 | 30.8 |

**Target Price Range**
2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 45 | (+30%) | *10%* |
| Low | 35 | (Nil) | *5%* |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 2 | 0 | 0 | 7 | 0 | 0 | 1 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 123 | 124 | 111 |
| to Sell | 85 | 90 | 106 |
| Hld's(000) | 48400 | 51648 | 48595 |

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 5.0 | 12.9 |
| 3 yr. | 60.3 | 50.1 |
| 5 yr. | 107.7 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15.69 | 15.77 | 16.42 | 17.00 | 16.96 | 17.17 | 18.31 | 17.19 | 15.94 | 25.45 | 30.09 | 25.64 | 27.48 | 27.73 | 30.36 | 33.50 | *30.90* | *32.75* | Revenues per sh | *39.00* |
| 2.87 | 2.94 | 2.98 | 3.35 | 3.11 | 3.65 | 3.66 | 3.84 | 3.04 | 3.78 | 3.81 | 3.95 | 3.98 | 4.09 | 5.00 | 5.40 | *5.65* | *5.95* | "Cash Flow" per sh | *7.00* |
| .98 | 1.05 | 1.14 | 1.21 | 1.04 | 1.31 | 1.36 | 1.38 | 1.39 | 1.60 | 1.64 | 1.69 | 1.74 | 1.76 | 1.83 | 1.93 | *2.10* | *2.25* | Earnings per sh A | *3.00* |
| .80 | .83 | .86 | .89 | .92 | .94 | .94 | .95 | .98 | 1.01 | 1.04 | 1.07 | 1.09 | 1.13 | .87 | 1.54 | *1.35* | *1.43* | Div'd Decl'd per sh B ■ | *1.75* |
| 2.55 | 2.58 | 2.81 | 2.42 | 2.08 | 2.13 | 1.23 | 1.57 | 1.53 | 1.78 | 2.22 | 3.50 | 2.94 | 2.95 | 3.63 | 3.99 | *3.80* | *2.95* | Cap'l Spending per sh | *2.75* |
| 8.96 | 9.39 | 9.71 | 10.06 | 10.31 | 10.54 | 10.98 | 11.14 | 13.29 | 12.65 | 11.90 | 12.25 | 12.84 | 13.52 | 14.37 | 14.82 | *15.60* | *16.45* | Book Value per sh C | *19.75* |
| 84.09 | 89.53 | 90.26 | 91.07 | 96.01 | 97.02 | 97.03 | 94.37 | 116.12 | 106.07 | 106.07 | 106.07 | 106.07 | 106.55 | 106.81 | 106.81 | *106.81* | *106.81* | Common Shs Outst'g D | *106.81* |
| 10.6 | 11.9 | 13.1 | 10.7 | 12.3 | 9.7 | 10.6 | 14.6 | 14.6 | 12.9 | 12.7 | 12.7 | 12.8 | 14.0 | 15.5 | 15.9 | *Bold figures are* | *Value Line* | Avg Ann'l P/E Ratio | *13.5* |
| .68 | .72 | .77 | .70 | .82 | .61 | .61 | .76 | .83 | .84 | .65 | .69 | .73 | .74 | .83 | .86 | *estimates* | | Relative P/E Ratio | *.90* |
| 7.7% | 6.6% | 5.8% | 6.9% | 7.2% | 7.4% | 6.5% | 4.7% | 4.8% | 4.9% | 5.0% | 4.9% | 4.9% | 4.6% | 3.1% | 5.0% | | | Avg Ann'l Div'd Yield | *4.3%* |
| | | | | | | 1776.2 | 1622.5 | 1851.4 | 2699.5 | 3191.8 | 2719.1 | 2914.1 | 2954.3 | 3243.1 | 3577.7 | *3300* | *3500* | Revenues ($mill) | *4175* |
| | | | | | | 144.6 | 141.0 | 146.5 | 181.0 | 179.1 | 181.3 | 188.0 | 190.4 | 198.1 | 208.7 | *225* | *245* | Net Profit ($mill) | *315* |
| | | | | | | 36.3% | 34.3% | 29.1% | 41.6% | 41.4% | 35.8% | 37.5% | 38.5% | 35.6% | 37.8% | *38.0%* | *38.0%* | Income Tax Rate | *38.0%* |
| | | | | | | .8% | 1.2% | 1.5% | 2.5% | 2.8% | 1.6% | 2.4% | .5% | 1.9% | 3.3% | *2.0%* | *2.0%* | AFUDC % to Net Profit | *1.0%* |
| | | | | | | 46.1% | 45.5% | 50.0% | 59.4% | 59.2% | 60.9% | 58.5% | 58.6% | 60.4% | 59.2% | *58.5%* | *58.0%* | Long-Term Debt Ratio | *48.0%* |
| | | | | | | 46.5% | 50.1% | 47.2% | 39.4% | 39.5% | 37.8% | 40.2% | 40.2% | 38.6% | 39.7% | *40.5%* | *41.0%* | Common Equity Ratio | *51.0%* |
| | | | | | | 2291.6 | 2099.5 | 3269.3 | 3409.8 | 3197.4 | 3433.7 | 3387.1 | 3585.3 | 3980.4 | 3986.3 | *4100* | *4280* | Total Capital ($mill) | *4150* |
| | | | | | | 2854.1 | 2270.7 | 2550.6 | 2523.6 | 2625.4 | 2847.6 | 3216.1 | 3425.0 | 3701.8 | 3945.3 | *4130* | *4215* | Net Plant ($mill) | *4375* |
| | | | | | | 8.3% | 8.7% | 6.1% | 7.6% | 8.1% | 7.5% | 7.8% | 7.4% | 7.1% | 7.3% | *7.5%* | *7.5%* | Return on Total Cap'l | *9.0%* |
| | | | | | | 11.7% | 12.3% | 9.0% | 13.1% | 13.7% | 13.5% | 13.4% | 12.8% | 12.6% | 12.8% | *13.5%* | *13.5%* | Return on Shr. Equity | *14.5%* |
| | | | | | | 12.3% | 12.6% | 9.1% | 13.0% | 13.7% | 13.8% | 13.7% | 13.1% | 12.8% | 13.1% | *13.5%* | *14.0%* | Return on Com Equity E | *14.5%* |
| | | | | | | 3.7% | 3.9% | 2.4% | 4.8% | 5.0% | 5.2% | 5.1% | 4.8% | 4.6% | 4.9% | *5.0%* | *5.0%* | Retained to Com Eq | *6.0%* |
| | | | | | | 73% | 71% | 74% | 64% | 65% | 63% | 63% | 64% | 64% | 63% | *63%* | *63%* | All Div'ds to Net Prof | *60%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $2891.4 mill. **Due in 5 Yrs** $1838.9 mill.
**LT Debt** $2203.6 mill. **LT Interest** $136.6 mill.
Incl. $484.0 mill. securitized bonds.
(LT interest earned: 3.1x)
**Leases, Uncapitalized** Annual rentals $18.1 mill.

**Pension Assets-12/06** $1.03 bill. **Oblig.** $1.08 bill.
**Pfd Stock** $43.0 mill. **Pfd Div'd** $2.0 mill.
430,000 shs. 4.25%-4.78%, cum., redeemable at $102.80-$103.625.
**Common Stock** 106,808,376 shs.
**as of 10/30/07**
**MARKET CAP: $3.7 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +1.5 | +2.5 | -1.9 |
| Avg. Indust. Use (MWH) | 1027 | 1022 | 1001 |
| Avg. Indust. Revs. per KWH (¢) | 7.90 | 8.20 | 8.40 |
| Capacity at Peak (Mw) | NMF | NMF | NMF |
| Peak Load, Summer (Mw) | 4254 | 4682 | 4958 |
| Annual Load Factor (%) | NMF | NMF | NMF |
| % Change Customers (avg.) | +.4 | +.7 | +1.5 |
| Fixed Charge Cov. (%) | 287 | 266 | 262 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 6.0% | 5.0% | *4.0%* |
| "Cash Flow" | 3.5% | 6.5% | *6.5%* |
| Earnings | 4.5% | 3.5% | *8.5%* |
| Dividends | 2.5% | 3.0% | *7.0%* |
| Book Value | 3.5% | 2.5% | *5.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 809.9 | 649.8 | 781.5 | 713.1 | 2954.3 |
| 2005 | 880.0 | 692.0 | 858.5 | 812.6 | 3243.1 |
| 2006 | 1034.8 | 784.6 | 956.3 | 802.0 | 3577.7 |
| 2007 | 984.4 | 725.1 | 804.9 | *785.6* | *3300* |
| 2008 | *1050* | *775* | *850* | *825* | *3500* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .46 | .35 | .59 | .35 | 1.76 |
| 2005 | .43 | .31 | .72 | .36 | 1.83 |
| 2006 | .41 | .43 | .72 | .38 | 1.93 |
| 2007 | .45 | .47 | .79 | *.39* | *2.10* |
| 2008 | *.50* | *.50* | *.80* | *.45* | *2.25* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .278 | .278 | .278 | .278 | 1.11 |
| 2005 | .29 | .29 | .29 | .29 | 1.16 |
| 2006 | .303 | .303 | .303 | .303 | 1.21 |
| 2007 | .325 | .325 | .325 | .325 | |
| 2008 | .35 | | | | |

**BUSINESS:** NSTAR is a holding company for Boston Edison Company, which supplies electricity to an area of approx. 590 sq. mi. in eastern Massachusetts, encompassing Boston and 39 surrounding towns and cities, and Commonwealth Energy (acq'd 8/99), which provides electric and gas service in eastern Massachusetts. Serves 1.1 million electric, 300,000 gas customers. Electric revenue breakdown, '06: residential, 43%; commercial, 52%; industrial, 5%; other, less than 1%. Sold fossil plants in '98, nuclear plant in '99. Fuel costs: 59% of revenues. '06 reported deprec. rate: 3.0%. Has 3,100 employees. Chairman, President & CEO: Thomas J. May. Inc.: Massachusetts. Address: 800 Boylston St., Boston, Massachusetts 02199-8003. Tel.: 617-424-2000. Internet: www.nstaronline.com.

**We have raised our 2007 earnings estimate for NSTAR by $0.05 a share, to $2.10.** Third-quarter profits were better than we expected, due in part to interest income associated with a tax matter. This added $0.03 to share net. Our revised estimate is still within the company's targeted range of $2.02-$2.12 a share. But, NSTAR stock is ranked 4 (Below Average) for year-ahead relative performance.

**We expect the company to continue to produce strong earnings growth over the 3- to 5-year period.** NSTAR has an electric regulatory agreement that runs through 2012. It provides for annual base rate increases and opportunities to earn additional incentive revenues. The utility may earn a return on equity of up to 12.5% (on a regulatory basis, which differs from a financial ROE) before a sharing mechanism kicks in. NSTAR can also reopen the regulatory agreement if its regulatory ROE falls below 8.5%, but we consider such a decline very unlikely. The utility faces no commodity risk, as it passes on any increases in power and gas costs to its customers. (It also passes on any decreases, which is why we estimate that revenues will decline in 2007, despite the increase in base rates mentioned above.) In all, we think NSTAR's target of 6%-8% annual earnings growth is attainable. Our 2008 forecast of $2.25 would produce an earnings increase within this goal.

**Earlier this month, the board of directors raised the dividend.** The board boosted the quarterly disbursement by $0.025 a share (7.7%). The increase was within NSTAR's target of providing 6%-8% annual dividend growth. We project that the company will attain this goal over the 2010-2012 period. NSTAR has been raising the dividend annually, but since one declaration was postponed from the fourth quarter of 2005 until the first period of 2006, the statistical array above shows unusual fluctuations.

**Conservative investors might consider this stock for its good yield,** which is above average even by utility standards. The stock is ranked 1 (Highest) for Safety. It offers respectable, risk-adjusted total returns over the 3- to 5-year period, thanks to NSTAR's solid earnings- and dividend-growth potential.

*Paul E. Debbas, CFA* *November 30, 2007*

(A) Diluted EPS. Excl. nonrecurring losses: '01, $1.66 net; '02, 17¢; '03, 4¢. '04,'05, & '06 EPS don't add to full-year total due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. There were only 3 div'd declarations in '05, 5 in '06. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '06: $2.5 bill., $23.52/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in '06: 12.5%; earned on avg. com. eq., '06: 13.3%. Regulatory Climate: Above Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 80 |
| Earnings Predictability | 95 |

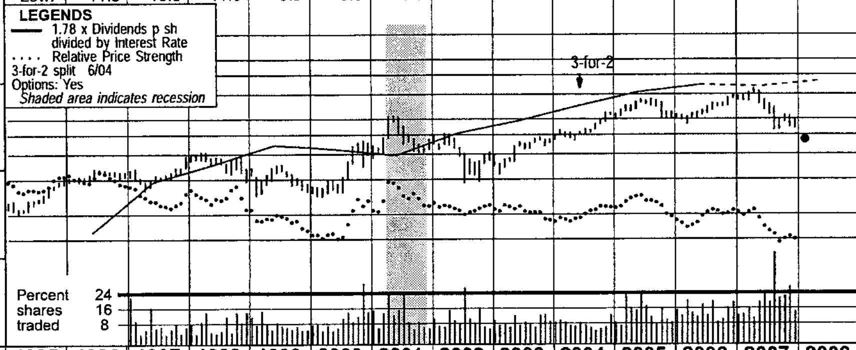
# PNM RESOURCES NYSE-PNM

RECENT PRICE **18.96** | P/E RATIO **13.4** (Trailing: 12.3; Median: 12.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **5.1%** | **VALUE LINE**

**TIMELINESS** 4 Raised 1/25/08
**SAFETY** 2 Raised 8/16/02
**TECHNICAL** 3 Raised 12/14/07
**BETA** .90 (1.00 = Market)

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 13.7 | 15.8 | 16.5 | 14.3 | 18.9 | 25.2 | 20.5 | 19.6 | 26.1 | 30.5 | 32.1 | 34.3 |
| Low: | 11.5 | 10.5 | 11.6 | 9.9 | 9.8 | 15.3 | 11.5 | 12.6 | 18.7 | 23.8 | 22.5 | 21.0 |

**LEGENDS**
— 1.78 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 6/04
Options: Yes
*Shaded area indicates recession*




**Target Price Range**
2010 | 2011 | 2012
64 48 40 32 24 20 16 12 8 6

### 2010-12 PROJECTIONS

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 25 | (+30%) | *11%* |
| Low | 17 | (-10%) | *3%* |

### Insider Decisions

| | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 3 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 3 | 0 | 2 | 0 | 0 | 1 | 0 | 0 | 0 |

### Institutional Decisions

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 99 | 79 | 70 |
| to Sell | 81 | 101 | 98 |
| Hld's(000) | 67772 | 78128 | 72969 |

**% TOT. RETURN 12/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -28.8 | 1.3 |
| 3 yr. | -6.8 | 25.2 |
| 5 yr. | 58.7 | 117.2 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13.68 | 13.60 | 13.95 | 14.44 | 12.90 | 14.10 | 18.12 | 17.43 | 18.96 | 27.46 | 40.09 | 19.92 | 24.11 | 26.54 | 30.19 | 32.25 | *32.60* | *33.75* | Revenues per sh | *41.25* |
| 1.76 | 2.10 | 2.34 | 2.55 | 2.38 | 2.61 | 2.58 | 3.04 | 2.82 | 3.16 | 4.31 | 2.83 | 3.05 | 3.14 | 3.56 | 3.57 | *3.45* | *4.00* | "Cash Flow" per sh | *5.00* |
| .21 | .50 | .81 | 1.11 | .91 | 1.15 | 1.25 | 1.50 | 1.29 | 1.55 | 2.61 | 1.07 | 1.15 | 1.43 | 1.59 | 1.72 | *1.35* | *1.65* | Earnings per sh A | *1.85* |
| -- | -- | -- | -- | -- | .24 | .42 | .51 | .53 | .53 | .53 | .57 | .61 | .63 | .79 | .86 | *.93* | *.97* | Div'd Decl'd per sh B ■† | *1.09* |
| 1.28 | 1.52 | 1.61 | 1.90 | 1.70 | 1.42 | 2.05 | 2.06 | 1.56 | 2.50 | 4.51 | 4.09 | 2.78 | 2.25 | 3.07 | 4.04 | *3.90* | *3.75* | Cap'l Spending per sh | *3.75* |
| 11.79 | 10.00 | 8.86 | 10.08 | 11.22 | 12.04 | 12.84 | 13.75 | 14.74 | 15.76 | 17.25 | 16.60 | 17.84 | 18.19 | 18.70 | 22.09 | *22.45* | *23.70* | Book Value per sh C | *25.90* |
| 62.66 | 62.66 | 62.66 | 62.66 | 62.66 | 62.66 | 62.66 | 62.66 | 61.05 | 58.68 | 58.68 | 58.68 | 60.39 | 60.46 | 68.79 | 76.65 | *77.00* | *80.00* | Common Shs Outst'g D | *80.00* |
| 29.1 | 16.5 | 9.5 | 7.5 | 10.6 | 11.0 | 10.0 | 9.8 | 9.5 | 8.5 | 7.3 | 15.1 | 14.7 | 15.0 | 17.1 | 15.6 | *14.0* | | Avg Ann'l P/E Ratio | *10.5* |
| 1.86 | 1.00 | .56 | .49 | .71 | .69 | .58 | .51 | .54 | .55 | .37 | .82 | .84 | .79 | .91 | .84 | *.74* | | Relative P/E Ratio | *.70* |
| -- | -- | -- | -- | -- | 1.9% | 3.3% | 3.5% | 4.4% | 4.1% | 2.8% | 3.5% | 3.6% | 2.9% | 2.9% | 3.2% | 4.9% | | Avg Ann'l Div'd Yield | *5.3%* |
| | | | | | | 1135.3 | 1092.4 | 1157.5 | 1611.3 | 2352.1 | 1169.0 | 1455.7 | 1604.8 | 2076.8 | 2471.7 | *2510* | *2700* | Revenues ($mill) | *3300* |
| | | | | | | 79.3 | 105.2 | 79.9 | 92.7 | 156.3 | 64.3 | 68.9 | 88.3 | 106.6 | 122.1 | *95* | *130* | Net Profit ($mill) | *150* |
| | | | | | | 37.1% | 34.9% | 34.6% | 44.5% | 34.2% | 24.5% | 29.0% | 28.2% | 31.1% | 24.7% | *25.0%* | *25.0%* | Income Tax Rate | *25.0%* |
| | | | | | | -- | -- | -- | -- | -- | -- | 1.7% | 3.4% | 3.4% | 3.8% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| | | | | | | 46.6% | 53.2% | 52.0% | 50.4% | 48.2% | 49.8% | 47.5% | 47.1% | 57.4% | 50.9% | *50.5%* | *49.5%* | Long-Term Debt Ratio | *48.5%* |
| | | | | | | 52.5% | 45.4% | 47.3% | 48.9% | 51.1% | 49.5% | 51.9% | 52.4% | 42.3% | 48.8% | *49.0%* | *50.0%* | Common Equity Ratio | *51.0%* |
| | | | | | | 1531.2 | 1896.4 | 1901.2 | 1891.3 | 1978.7 | 1966.9 | 2077.3 | 2098.9 | 3044.4 | 3470.7 | *3510* | *3765* | Total Capital ($mill) | *4050* |
| | | | | | | 1573.2 | 1593.8 | 1582.4 | 1617.3 | 1781.0 | 1867.3 | 2194.4 | 2324.6 | 2984.1 | 3761.9 | *3890* | *4000* | Net Plant ($mill) | *4200* |
| | | | | | | 6.7% | 6.9% | 5.9% | 6.6% | 9.5% | 4.7% | 4.7% | 5.3% | 4.7% | 4.9% | *4.0%* | *5.0%* | Return on Total Cap'l | *5.0%* |
| | | | | | | 9.7% | 11.8% | 8.8% | 9.9% | 15.3% | 6.5% | 6.3% | 7.9% | 8.2% | 7.2% | *5.5%* | *7.0%* | Return on Shr. Equity | *7.0%* |
| | | | | | | 9.8% | 12.1% | 8.8% | 10.0% | 15.4% | 6.5% | 6.3% | 8.0% | 8.2% | 7.2% | *5.5%* | *7.0%* | Return on Com Equity E | *7.0%* |
| | | | | | | 6.5% | 8.4% | 5.2% | 6.5% | 12.3% | 3.1% | 3.0% | 4.5% | 4.3% | 3.7% | *1.5%* | *3.0%* | Retained to Com Eq | *3.0%* |
| | | | | | | 34% | 31% | 42% | 35% | 20% | 53% | 53% | 44% | 48% | 49% | *74%* | *58%* | All Div'ds to Net Prof | *58%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $1566.9 mill. **Due in 5 Yrs** $2161.5 mill.
**LT Debt** $1233.6 mill. **LT Interest** $92.3 mill.
(LT interest earned: 2.6x)
**Pension Assets-12/06** $485.8 mill. **Oblig.** $535.7 mill.
**Pfd Stock** $11.5 mill. **Pfd Div'd** $.6 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

**Common Stock** 76,777,076 shs. as of 11/1/07
**MARKET CAP: $1.9 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.4 | +2.9 | +3.5 |
| Avg. Indust. Use (MWH) | 4428 | 4544 | 4756 |
| Avg. Indust. Revs. per KWH (¢) | 4.82 | 4.79 | 4.71 |
| Capacity at Peak (Mw) | 1729 | 1744 | 1934 |
| Peak Load, Summer (Mw) | 1655 | 1779 | 1855 |
| Annual Load Factor (%) | 65.0 | 64.8 | 65.0 |
| % Change Customers (yr-end) | +2.6 | +2.9 | +2.7 |
| Fixed Charge Cov. (%) | 250 | 165 | 166 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 8.0% | .5% | 5.5% |
| "Cash Flow" | 3.0% | -- | 6.5% |
| Earnings | 4.0% | -2.5% | 2.5% |
| Dividends | -- | 7.5% | 6.0% |
| Book Value | 6.0% | 4.5% | 4.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 437.4 | 370.4 | 386.8 | 410.2 | 1604.8 |
| 2005 | 427.9 | 405.3 | 597.1 | 646.5 | 2076.8 |
| 2006 | 655.8 | 546.7 | 650.2 | 619.0 | 2471.7 |
| 2007 | 653.5 | 580.7 | 629.4 | *646.4* | *2510* |
| 2008 | *700* | *610* | *680* | *710* | *2700* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .40 | .28 | .45 | .30 | 1.43 |
| 2005 | .50 | .22 | .46 | .41 | 1.59 |
| 2006 | .38 | .23 | .62 | .49 | 1.72 |
| 2007 | .38 | .26 | .41 | *.30* | *1.35* |
| 2008 | *.40* | *.30* | *.55* | *.40* | *1.65* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■† Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .153 | .16 | .16 | .16 | .63 |
| 2005 | .185 | .185 | .20 | .20 | .77 |
| 2006 | .20 | .20 | .22 | .22 | .84 |
| 2007 | .22 | .23 | .23 | .23 | .91 |
| 2008 | | | | | |

**BUSINESS:** PNM Resources, parent of Public Service Company of New Mexico, sells electricity (86% of revenues), gas (14%), other less than (1%) in north-central New Mexico (popul.: 1,300,000). Acquired TNP Enterprises 6/05. Largest customer: City of Albuquerque. Elect. rev. breakdown: resid., 35%; commer., 35%; indust, 16%; other, 14%. Area's military establishments are major customers. Fuels: coal, 70%; nuclear, 24%; gas/oil, 6%. Fuel costs: 59% of revs.; labor costs: 16%. '06 reported deprec. rates: 2.4% elec., 2.9% gas. Est'd plant age: 11 years. Has 5,675 employees. Chairman, Chief Executive Officer & President: Jeffry E. Sterba. Inc.: New Mexico. Address: Alvarado Square, Albuquerque, New Mexico 87158. Tel.: 505-241-2700. Internet: www.pnmresources.com.

**PNM Resources is increasing emphasis on its electric business.** It has an agreement to sell its natural gas operations to Continental Energy Systems and, conditioned on the sale, to buy Continental's regulated Texas electric delivery holdings. The gas operations will be sold for $620 million, the electric bought for $202.5 million. Both transactions will be for 100% cash. The electric enterprises, which own no generation, are supplied with energy under long-term purchase-power contracts. Regulation permits pass-through of all power costs on a monthly basis. The purchase is expected to be slightly accretive to earnings in the first year and more so thereafter. Simultaneous closings of both deals are expected by yearend.

**The company has filed its first electric general rate case in 20 years.** It asked for an annual increase of $82.4 million, based on an allowed return on equity of 10.75%, down from the present 12.52%. Chief drivers of the hike are rising fuel prices, higher O&M expenses, and the cost of the Afton gas-fired plant's upgrades. The proposal includes a fuel and purchased power cost adjustment clause and consumption-based rates designed to encourage energy efficiency. Finally, it seeks recovery of environmental outlays as they are incurred. This would reimburse PNM in a timely manner for its $94 million share of costs to improve pollution controls at the San Juan coal-fired station. A decision on the request is due in early May.

**Earnings should have no difficulty exceeding 2007's poor results.** Last year's profits were hurt by cost overruns in converting Afton to a combined-cycle unit and by weaker-than-expected plant operations. The current year will benefit from payroll savings resulting from an outsourcing contract with Alliance Data and from higher rates. All told, we project 2008 earnings will rise 22% over last year's estimated $1.35 a share. Smaller gains are likely through 2010-2012. The stock is untimely.

**The yield is a full percentage point above the industry norm.** And our projection of higher earnings to 2010-2012 suggests dividend growth over the same time frame well above that of the group. The stock might interest income-oriented investors.

*Arthur H. Medalie* *February 8, 2008*

(A) EPS diluted. Next earnings report due mid-Feb. Excl. nonrecur. gains (losses): '92, ($2.28); '93, ($1.90); '94, 7¢; '95, net 23¢; '97, 3¢; '98, net (16¢); '99, 5¢; '00, 14¢; '01, (10¢); '03, 45¢; '05, (56¢). (B) Div'ds historically paid in mid-Feb., mid-May, mid-Aug., and mid-Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '06: $16.68/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. Elect. ROE allowed in '90: 12.52%; earned on avg. com. eq., '06: 8.1%. Regulatory Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 85 |
| Price Growth Persistence | 80 |
| Earnings Predictability | 60 |

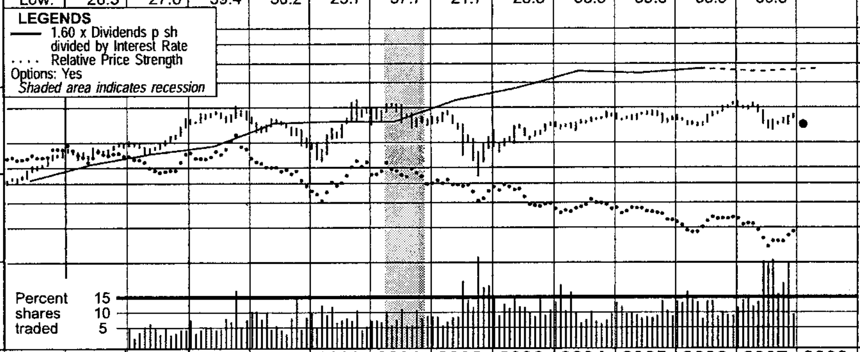
# PINNACLE WEST NYSE-PNW

| RECENT PRICE | 39.53 | P/E RATIO | 13.4 (Trailing: 13.0 Median: 14.0) | RELATIVE P/E RATIO | 0.84 | DIV'D YLD | 5.4% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

TIMELINESS **3** Raised 10/5/07
SAFETY **1** Raised 5/16/03
TECHNICAL **1** Raised 2/8/08
BETA .80 (1.00 = Market)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 32.3 | 42.8 | 49.3 | 43.4 | 52.7 | 50.7 | 46.7 | 40.5 | 45.8 | 46.7 | 51.0 |
| Low: | 26.3 | 27.6 | 39.4 | 30.2 | 25.7 | 37.7 | 21.7 | 28.3 | 36.3 | 39.8 | 38.3 |

| | |
|---|---|
| High: | 51.7 |
| Low: | 36.8 |




**Target Price Range**
2010 | 2011 | 2012

**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 45 | (+15%) | 8% |
| Low | 40 | (Nil) | 6% |

**Insider Decisions**

| | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 2 |
| to Sell | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 2 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 155 | 159 | 135 |
| to Sell | 124 | 132 | 135 |
| Hld's(000) | 79933 | 88538 | 87323 |

**% TOT. RETURN 12/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -12.2 | 1.3 |
| 3 yr. | 9.8 | 25.2 |
| 5 yr. | 55.7 | 117.2 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16.95 | 19.39 | 19.66 | 19.28 | 19.08 | 20.77 | 23.52 | 25.12 | 28.57 | 43.50 | 53.66 | 28.90 | 30.87 | 31.59 | 30.16 | 34.03 | *35.10* | *37.40* | Revenues per sh | *43.65* |
| d1.39 | 4.70 | 5.25 | 5.09 | 5.16 | 5.90 | 7.12 | 7.34 | 7.73 | 7.99 | 8.72 | 7.01 | 7.33 | 6.93 | 5.76 | 6.76 | *6.85* | *7.45* | "Cash Flow" per sh | *8.90* |
| d3.90 | 1.73 | 1.95 | 1.99 | 2.22 | 2.47 | 2.76 | 2.85 | 3.18 | 3.35 | 3.68 | 2.53 | 2.52 | 2.58 | 2.24 | 3.17 | 2.94 | *2.55* | Earnings per sh A | *2.95* |
| -- | -- | .20 | .83 | .93 | 1.03 | 1.13 | 1.23 | 1.33 | 1.43 | 1.53 | 1.63 | 1.73 | 1.83 | 1.93 | 2.03 | 2.10 | *2.12* | Div'd Decl'd per sh B■† | *2.28* |
| 2.10 | 2.57 | 2.69 | 2.92 | 3.38 | 2.95 | 3.63 | 3.76 | 4.05 | 7.76 | 12.27 | 9.81 | 7.60 | 5.86 | 6.39 | 7.38 | *10.95* | *10.65* | Cap'l Spending per sh | *9.90* |
| 15.23 | 17.00 | 18.87 | 20.32 | 21.49 | 22.51 | 23.90 | 25.50 | 26.00 | 28.09 | 29.46 | 29.44 | 31.00 | 32.14 | 34.57 | 34.47 | *35.30* | *36.25* | Book Value per sh C | *37.55* |
| 87.01 | 87.16 | 87.42 | 87.43 | 87.52 | 87.52 | 84.83 | 84.83 | 84.83 | 84.83 | 84.83 | 91.26 | 91.29 | 91.79 | 99.08 | 99.96 | *100.40* | *100.50* | Common Shs Outst'g D | *100.80* |
| -- | 10.8 | 11.5 | 9.6 | 10.8 | 11.8 | 11.8 | 15.2 | 11.9 | 11.3 | 12.0 | 14.4 | 14.0 | 15.8 | 19.2 | 13.7 | 13.4 | | Avg Ann'l P/E Ratio | *14.0* |
| -- | .66 | .68 | .63 | .72 | .74 | .68 | .79 | .68 | .73 | .61 | .79 | .80 | .83 | 1.02 | .74 | .71 | | Relative P/E Ratio | *.95* |
| -- | -- | .9% | 4.3% | 3.9% | 3.5% | 3.5% | 2.8% | 3.5% | 3.8% | 3.5% | 4.5% | 4.9% | 4.5% | 4.5% | 4.7% | 5.4% | | Avg Ann'l Div'd Yield | *5.4%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $3503.0 mill. **Due in 5 Yrs** $746.8 mill.
**LT Debt** $3229.4 mill. **LT Interest** $194.4 mill.
(LT interest earned: 3.3x)

**Pension Assets-12/06** $1.21 bill. **Oblig.** $1.67 bill.

**Pfd Stock** None

**Common Stock** 100,385,036 shs. **as of 11/2/07**
**MARKET CAP: $4.1 billion (Mid Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1995.0 | 2130.6 | 2423.4 | 3690.2 | 4551.4 | 2637.3 | 2817.9 | 2899.7 | 2988.0 | 3401.8 | 3523.6 | *3760* | Revenues ($mill) | *4400* |
| 248.7 | 252.6 | 270.8 | 283.6 | 312.2 | 215.2 | 230.6 | 235.2 | 223.2 | 317.1 | *295* | *255* | Net Profit ($mill) | *295* |
| 37.7% | 39.5% | 38.3% | 44.1% | 40.6% | 39.1% | 31.4% | 35.4% | 36.2% | 33.0% | *33.0%* | *33.0%* | Income Tax Rate | *33.0%* |
| 6.5% | 7.4% | 4.3% | 7.6% | 15.3% | 20.5% | 6.2% | 6.9% | 10.4% | 6.6% | *4.0%* | *4.0%* | AFUDC % to Net Profit | *4.0%* |
| 50.5% | 47.6% | 50.0% | 45.1% | 51.7% | 51.8% | 50.6% | 46.7% | 43.2% | 48.4% | *48.5%* | *49.0%* | Long-Term Debt Ratio | *49.5%* |
| 45.6% | 50.2% | 50.0% | 54.9% | 48.3% | 48.2% | 49.4% | 53.3% | 56.8% | 51.6% | *51.5%* | *51.0%* | Common Equity Ratio | *50.5%* |
| 4442.9 | 4307.6 | 4411.8 | 4337.8 | 5172.4 | 5567.9 | 5727.5 | 5535.2 | 6033.4 | 6678.8 | *6875* | *7025* | Total Capital ($mill) | *7515* |
| 4677.6 | 4730.6 | 4778.5 | 5133.2 | 5907.3 | 6479.4 | 7480.1 | 7535.5 | 7577.1 | 7881.9 | *8590* | *9320* | Net Plant ($mill) | *10930* |
| 7.4% | 7.6% | 7.9% | 8.1% | 7.6% | 5.4% | 5.5% | 5.6% | 5.0% | 6.2% | *6.0%* | *5.0%* | Return on Total Cap'l | *5.5%* |
| 11.3% | 11.2% | 12.3% | 11.9% | 12.5% | 8.0% | 8.1% | 8.0% | 6.5% | 9.2% | *8.5%* | *7.0%* | Return on Shr. Equity | *8.0%* |
| 11.6% | 11.2% | 12.2% | 11.9% | 12.5% | 8.0% | 8.1% | 8.0% | 6.5% | 9.2% | *8.5%* | *7.0%* | Return on Com Equity E | *8.0%* |
| 6.9% | 6.4% | 7.1% | 6.8% | 7.3% | 2.9% | 2.6% | 2.3% | 1.0% | 3.4% | *2.5%* | *1.0%* | Retained to Com Eq | *2.0%* |
| 44% | 45% | 42% | 43% | 41% | 64% | 68% | 71% | 85% | 63% | *71%* | *83%* | All Div'ds to Net Prof | *77%* |

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.2 | +4.4 | +5.6 |
| Avg. Indust. Use (MWH) | 707 | 670 | 730 |
| Avg. Indust. Revs. per KWH (¢) | 5.57 | 6.28 | 6.87 |
| Capacity at Peak (Mw) | 7758 | 7412 | 7652 |
| Peak Load, Summer (Mw) | 6402 | 7000 | 7652 |
| Annual Load Factor (%) | 52.2 | 50.0 | 48.0 |
| % Change Customers (yr-end) | +3.7 | +4.3 | +4.4 |
| Fixed Charge Cov. (%) | 261 | 278 | 324 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 5.0% | -5.5% | *5.5%* |
| "Cash Flow" | 2.0% | -4.5% | *5.5%* |
| Earnings | 2.0% | -5.0% | *1.5%* |
| Dividends | 7.5% | 6.0% | *3.0%* |
| Book Value | 4.5% | 4.0% | *2.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 566.3 | 711.9 | 886.8 | 734.7 | 2899.7 |
| 2005 | 585.0 | 755.8 | 955.6 | 691.6 | 2988.0 |
| 2006 | 670.2 | 925.0 | 1076.5 | 730.1 | 3401.8 |
| 2007 | 695.1 | 863.4 | 1205.9 | 759.2 | 3523.6 |
| 2008 | *750* | *910* | *1260* | *840* | *3760* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .34 | .78 | 1.14 | .32 | 2.58 |
| 2005 | .26 | .88 | .86 | .24 | 2.24 |
| 2006 | .12 | 1.11 | 1.84 | .10 | 3.17 |
| 2007 | .16 | .78 | 1.97 | .03 | 2.94 |
| 2008 | *.15* | *.80* | *1.50* | *.10* | *2.55* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■† Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .45 | .45 | .45 | .475 | 1.83 |
| 2005 | .475 | .475 | .475 | .50 | 1.93 |
| 2006 | .50 | .50 | .50 | .525 | 2.03 |
| 2007 | .525 | .525 | .525 | .525 | 2.10 |
| 2008 | | | | | |

**BUSINESS:** Pinnacle West Capital Corporation (parent of Arizona Public Service) supplies electricity to approx. 1,780,000 people in 11 of 15 Arizona counties. Electric revenue sources: residential, 51%; commercial, industrial, and other, 49%. Power costs: 36% of electric revenues; labor costs: 13% of total revenues. The mining industry is the largest industrial customer. Energy sources: coal, 31%; nuclear, 17%; gas & other, 17%; purchased power, 35%. Has 7,140 employees. Reported '06 depreciation rate: 3.1%. Est'd plant age: 10 years. Chairman & Chief Executive Officer: William J. Post. Pres.: Jack E. Davis. Inc.: Arizona. Address: 400 E. Van Buren St., Suite 700, P.O. Box 52132, Phoenix, AZ 85072-2132. Tel.: 602-379-2568. Internet: www.pinnaclewest.com.

**Pinnacle West plans new transmission lines to enhance import capability.** Construction is well under way on a 100-mile, 500-kilovolt project around the greater Phoenix metropolitan area, which accounts for about 80% of the company's load requirements. The $160 million line should begin serving customers this summer. Under discussion is development of a 300-mile to 400-mile line from southwestern New Mexico into southeastern Arizona. The line's 1,200 megawatts of capacity would bolster the regional grid and provide a major east-west interconnection where none currently exists. Management has also proposed building a 122-mile line from the Palo Verde nuclear station to Yuma, Arizona to ensure adequate power in that area. For the longer term, PNW is considering a venture with partners for a 600-mile, $3 billion line from Wyoming to the Southwest to gain access to inexpensive coal and wind resources.

**The company's ongoing requests for power have met with good response.** Offers received over the last two years have resulted in purchased-power agreements for 1,200 megawatts (mw) from various sources for delivery starting in June, 2007. Too, PNW will buy the 40-mw output of a wind farm for 20 years and has approval for a 96-mw peaking facility adjacent to its existing plant in Yuma. Since outlays for these additions and for the transmission system won't be fully covered by cash flow, some debt and equity offerings will be necessary to close the gap.

**Earnings are headed lower in 2008.** A repetition of last year's favorable weather conditions that lifted 2007's third-quarter earnings to a record high can't be counted on this year. Other negatives include the absence of 2007's one-time tax benefits and weakness in SunCor's land sales because of a depressed housing market. On balance, we estimate 2008 earnings will decline 13%, to $2.55 a share. New plants on line point to gains over the coming 3 to 5 years.

**Despite mid-2007's disappointing rate order, dividend growth prospects still exceed those of the group.** What's more, finances are strong. PNW remains an above-average electric utility choice, in our opinion.

*Arthur H. Medalie* *February 8, 2008*

(A) Diluted egs. Excl. nonrecurring gains (losses): '91, ($4.68); '93, 22¢; '94, 31¢; '95, net 6¢; '99, ($1.20); '02, (77¢); excl. gains (losses) from discontinued ops.: '91, $1.76; '92, 7¢; '99, ($1.97); '00, 22¢; '05, (36¢); '06, 10¢. Next earnings report due late Apr. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Divd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def. chgs. In '06: $9.51/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in '05: 10.25%; earned on avg. com. eq., '06: 9.2%. Reg. Clim.: Avg.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 20 |
| Earnings Predictability | 60 |

# PPL CORPORATION NYSE-PPL

| RECENT PRICE | 49.23 | P/E RATIO | 18.3 (Trailing: 18.6 / Median: 12.0) | RELATIVE P/E RATIO | 1.09 | DIV'D YLD | 2.7% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 3 Raised 8/10/07

**SAFETY** 2 Raised 6/2/06

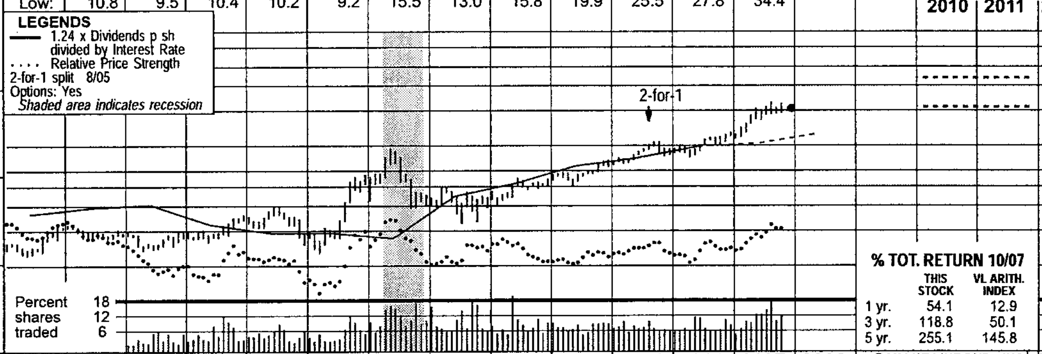
**TECHNICAL** 3 Lowered 10/12/07

**BETA** .90 (1.00 = Market)

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 13.0 | 12.1 | 14.5 | 16.0 | 23.1 | 31.2 | 20.0 | 22.2 | 27.1 | 33.7 | 37.3 | 52.8 |
| Low: | 10.8 | 9.5 | 10.4 | 10.2 | 9.2 | 15.5 | 13.0 | 15.8 | 19.9 | 25.5 | 27.8 | 34.4 |

**Target Price Range** 2010 | 2011 | 2012

**LEGENDS**
—— 1.24 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 8/05
Options: Yes
*Shaded area indicates recession*




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 70 | (+40%) | *12%* |
| Low | 50 | (Nil) | *4%* |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 1 | 0 | 2 | 1 | 0 | 5 |
| to Sell | 1 | 0 | 0 | 5 | 0 | 2 | 1 | 0 | 5 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 191 | 213 | 163 |
| to Sell | 196 | 183 | 235 |
| Hld's(000) | 238199 | 227703 | 236649 |

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 54.1 | 12.9 |
| 3 yr. | 118.8 | 50.1 |
| 5 yr. | 255.1 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8.44 | 9.03 | 8.96 | 8.76 | 8.63 | 8.94 | 9.17 | 12.03 | 15.97 | 19.59 | 19.53 | 16.38 | 15.75 | 15.37 | 16.36 | 17.92 | *18.30* | *19.75* | Revenues per sh | *25.50* |
| 1.86 | 1.90 | 1.98 | 1.84 | 2.05 | 2.14 | 2.11 | 2.43 | 2.56 | 3.32 | 3.51 | 3.20 | 3.60 | 3.59 | 3.84 | 4.26 | *5.00* | *4.80* | "Cash Flow" per sh | *7.75* |
| 1.00 | 1.01 | 1.04 | .84 | .97 | 1.03 | .99 | 1.12 | 1.01 | 1.64 | 1.79 | 1.54 | 1.84 | 1.87 | 1.92 | 2.29 | *2.75* | *2.45* | Earnings per sh A | *4.50* |
| .78 | .80 | .83 | .84 | .84 | .84 | .84 | .67 | .50 | .53 | .53 | .72 | .77 | .82 | .96 | 1.10 | *1.22* | *1.34* | Div'd Decl'd per sh B ■ | *2.20* |
| 1.23 | 1.39 | 1.60 | 1.62 | 1.26 | 1.11 | .93 | .97 | 1.11 | 1.59 | 2.99 | 2.74 | 2.17 | 1.94 | 2.13 | 3.62 | *4.70* | *4.35* | Cap'l Spending per sh | *4.25* |
| 7.58 | 7.79 | 7.97 | 7.89 | 8.15 | 8.44 | 8.45 | 5.69 | 5.61 | 6.94 | 6.33 | 6.71 | 9.19 | 11.21 | 11.62 | 13.30 | *13.90* | *15.10* | Book Value per sh C | *19.75* |
| 303.31 | 303.77 | 304.26 | 310.96 | 318.81 | 325.33 | 332.50 | 314.82 | 287.39 | 290.08 | 293.16 | 331.47 | 354.72 | 378.14 | 380.15 | 385.04 | *372.00* | *372.00* | Common Shs Outst'g D | *360.00* |
| 11.4 | 12.9 | 14.1 | 13.0 | 10.8 | 11.4 | 10.8 | 10.9 | 13.4 | 8.9 | 12.4 | 11.1 | 10.6 | 12.5 | 15.1 | 14.1 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.0* |
| .73 | .78 | .83 | .85 | .72 | .71 | .62 | .57 | .76 | .58 | .64 | .61 | .60 | .66 | .80 | .76 | *Value Line* | | Relative P/E Ratio | *.95* |
| 6.8% | 6.1% | 5.7% | 7.7% | 8.0% | 7.1% | 7.8% | 5.5% | 3.7% | 3.6% | 2.4% | 4.2% | 4.0% | 3.5% | 3.3% | 3.4% | *estimates* | | Avg Ann'l Div'd Yield | *3.6%* |

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3049.0 | 3786.0 | 4590.0 | 5683.0 | 5725.0 | 5429.0 | 5587.0 | 5812.0 | 6219.0 | 6899.0 | *6800* | *7350* | Revenues ($mill) | *9200* |
| 348.0 | 393.0 | 332.0 | 500.0 | 576.0 | 536.0 | 667.0 | 692.0 | 739.0 | 899.0 | *1070* | *955* | Net Profit ($mill) | *1700* |
| 41.5% | 40.7% | 33.5% | 36.3% | 29.7% | 25.7% | 27.1% | 22.8% | 14.0% | 23.2% | *17.0%* | *35.0%* | Income Tax Rate | *35.0%* |
| 2.0% | 2.3% | 2.1% | 4.0% | 4.3% | 3.4% | 1.2% | .7% | 1.1% | 2.6% | *6.0%* | *6.0%* | AFUDC % to Net Profit | *2.0%* |
| 46.1% | 59.1% | 65.7% | 65.4% | 64.8% | 66.5% | 71.1% | 61.6% | 57.5% | 55.4% | *56.5%* | *53.0%* | Long-Term Debt Ratio | *48.5%* |
| 48.0% | 34.2% | 28.2% | 29.5% | 23.7% | 25.1% | 28.5% | 37.9% | 42.0% | 42.2% | *41.0%* | *44.5%* | Common Equity Ratio | *49.5%* |
| 5854.0 | 5229.0 | 5716.0 | 6826.0 | 7845.0 | 8868.0 | 11455 | 11171 | 10513 | 12151 | *12625* | *12700* | Total Capital ($mill) | *14400* |
| 6820.0 | 4480.0 | 5644.0 | 5948.0 | 6135.0 | 9566.0 | 10446 | 11209 | 10916 | 12069 | *13050* | *13850* | Net Plant ($mill) | *15300* |
| 7.6% | 9.5% | 7.9% | 9.7% | 9.6% | 8.8% | 7.6% | 8.4% | 9.4% | 9.4% | *10.0%* | *9.5%* | Return on Total Cap'l | *13.5%* |
| 11.0% | 18.4% | 16.9% | 21.2% | 20.8% | 18.1% | 20.2% | 16.1% | 16.5% | 16.6% | *19.5%* | *16.0%* | Return on Shr. Equity | *23.0%* |
| 11.5% | 20.6% | 19.0% | 23.6% | 28.2% | 21.1% | 19.6% | 16.3% | 16.7% | 17.3% | *20.5%* | *16.5%* | Return on Com Equity E | *23.5%* |
| 1.8% | 6.4% | 9.4% | 16.1% | 20.2% | 12.4% | 11.7% | 9.3% | 8.8% | 9.3% | *11.5%* | *8.0%* | Retained to Com Eq | *12.5%* |
| 86% | 71% | 54% | 35% | 35% | 49% | 43% | 43% | 47% | 47% | *45%* | *54%* | All Div'ds to Net Prof | *48%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $7833.0 mill. **Due in 5 Yrs** $2528.0 mill.
**LT Debt** $7171.0 mill. **LT Interest** $457.0 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 3.3x)
**Leases, Uncapitalized** Annual rentals $49.0 mill.
**Pension Assets-12/06** $5.18 bill. **Oblig.** $5.54 bill.
**Pfd Stock** $301.0 mill. **Pfd Div'd** $18.0 mill.
505,189 shs. 3.35%-6.75%, $100 par, cumulative, callable $102.00-$110.00; 10 mill. shs. 6.25%, $100 liq. preference, redeemable after 4/6/11.
**Common Stock** 372,196,010 shs. as of 10/31/07
**MARKET CAP: $18 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.4 | +4.6 | -1.8 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Winter (Mw) F | 7199 | 7035 | 7554 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.6 | +1.1 | +.9 |

| Fixed Charge Cov. (%) | 264 | 259 | 300 |
|---|---|---|---|

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 6.5% | -2.0% | *7.5%* |
| "Cash Flow" | 7.0% | 4.5% | *12.0%* |
| Earnings | 8.0% | 6.5% | *14.0%* |
| Dividends | 1.5% | 13.0% | *15.0%* |
| Book Value | 4.0% | 14.0% | *8.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 1520 | 1362 | 1465 | 1465 | 5812.0 |
| 2005 | 1600 | 1478 | 1643 | 1498 | 6219.0 |
| 2006 | 1781 | 1642 | 1752 | 1724 | 6899.0 |
| 2007 | 1638 | 1613 | 1763 | *1786* | *6800* |
| 2008 | *1850* | *1750* | *1900* | *1850* | *7350* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .52 | .36 | .52 | .47 | 1.87 |
| 2005 | .45 | .46 | .51 | .50 | 1.92 |
| 2006 | .73 | .52 | .58 | .46 | 2.29 |
| 2007 | .63 | .63 | .93 | *.56* | *2.75* |
| 2008 | *.60* | *.60* | *.65* | *.60* | *2.45* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .18 | .193 | .193 | .193 | .76 |
| 2004 | .193 | .205 | .205 | .205 | .81 |
| 2005 | .205 | .23 | .23 | .25 | .92 |
| 2006 | .25 | .275 | .275 | .275 | 1.08 |
| 2007 | .275 | .305 | .305 | .305 | |

**BUSINESS:** PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to about 1.4 million customers in a 10,000-square-mile area in eastern & central Pennsylvania. Distributes gas to 110,000 customers. Also has subs. in power generation & marketing, foreign electricity distribution in U.K. (2.6 million customers) and Latin America (1.1 million customers). Electric revenue breakdown & generating sources not provided. Fuel costs: 32% of revenues. '06 deprec. rate: 3.8%. Has 12,600 employees. Chairman, President & CEO: James H. Miller. Inc.: Pennsylvania. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

**PPL has reached a settlement of its general rate case.** This calls for a distribution rate increase of $55.0 million (1.7%). The agreement, which has the recommendation of an administrative law judge, is subject to the approval of the Pennsylvania commission. If approved, it will take effect at the start of 2008.

**The company has completed the sale of the last of its three utilities in Latin America.** In all, these properties fetched $851 million, before taxes and transaction costs. PPL is using the proceeds to fund a $750 million stock buyback. The company has already recorded a modest gain on the first two sales, but the third gain, at an estimated $205 million-$225 million after taxes, will be the largest, by far. In all, the gains are expected to total $251 million-$271 million. We are *excluding* this income from our presentation because it is from discontinued operations.

**Earnings will probably decline in 2008.** PPL will lose $0.11 a share of earnings from its synthetic fuel investments, since the synfuel credits will cease at the end of 2007. Also, earnings in 2007 benefited from some unusual tax credits. Our 2008 estimate is at the top of PPL's targeted range of $2.35-$2.45 a share. But . . .

**Earnings should rise sharply in 2010.** The price that PPL Energy Supply may charge to its utility sibling in Pennsylvania is now limited by a price structure that, although increasing each year, is well below market rates. Since customers in PPL's service area will be paying higher market-based rates beginning in 2010, this will benefit suppliers such as PPL Energy Supply. Based on higher observed prices for energy and capacity in 2010, PPL has raised its profit guidance for that year from $3.50 a share to $4.00-$4.60. In order to lessen the rate shock that customers would otherwise experience then, the company has proposed a 54-month rate phase-in plan.

**This stock's valuation is higher than it has been historically, in anticipation of much greater profits beginning in 2010.** Dividends should be much higher over that time, too. The current yield is below average for a utility, but 3- to 5-year total-return potential is above the utility norm.

*Paul E. Debbas, CFA* *November 30, 2007*

**(A)** Diluted EPS. Excl. nonrec. gains (losses): '97, (9¢); '98, ($2.85); '99, 41¢; '00, 8¢; '01, ($1.18) net; '02, (89¢); '03, 24¢; '04, 3¢; '05, (2¢); '07, (12¢); gain (losses) on disc. ops.: '03, (6¢); '04, (1¢); '05, (12¢); '07, 19¢. Next earnings report due early Feb. **(B)** Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '06: $6.25/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Fair value. Rate allowed on com. eq. in '05: 10.7%; earn. on avg. com. eq., '06: 17.8%. Regulat. Climate: Avg. **(F)** Summer peak in '06.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 95 |
| Earnings Predictability | 80 |

# PROGRESS ENERGY NYSE-PGN

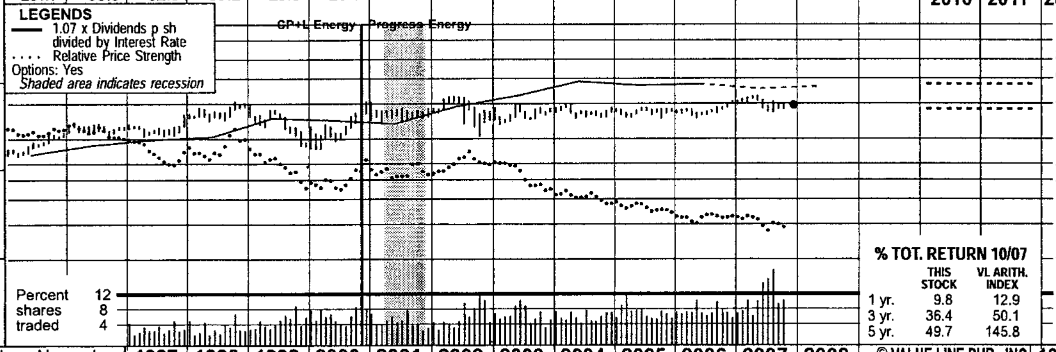
| RECENT PRICE | P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|
| 47.37 | 16.2 (Trailing: 15.9 / Median: 14.0) | 0.96 | 5.2% | VALUE LINE |

**TIMELINESS** 3 Lowered 7/27/07
**SAFETY** 2 Lowered 6/7/02
**TECHNICAL** 3 Raised 11/2/07
**BETA** .85 (1.00 = Market)

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 38.8 | 42.7 | 49.6 | 47.9 | 49.4 | 49.3 | 52.7 | 48.0 | 47.9 | 46.0 | 49.6 | 52.8 |
| Low: | 33.8 | 32.8 | 39.2 | 29.3 | 28.3 | 38.8 | 32.8 | 37.4 | 40.1 | 40.2 | 40.3 | 43.1 |

**Target Price Range** 2010 | 2011 | 2012

LEGENDS
— 1.07 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+25%) | 10% |
| Low | 45 | (-5%) | 4% |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 1 | 1 | 2 | 4 | 1 | 5 | 0 | 0 | 0 |
| to Sell | 2 | 1 | 2 | 10 | 2 | 5 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 217 | 212 | 222 |
| to Sell | 164 | 173 | 178 |
| Hld's(000) | 158683 | 151020 | 160423 |

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 9.8 | 12.9 |
| 3 yr. | 36.4 | 50.1 |
| 5 yr. | 49.7 | 145.8 |

Progress Energy was formed on November 30, 2000 through the merger of CP&L Energy and Florida Progress. Florida Progress common shareholders exchanged each share held for $54 in cash and/or CP&L common stock. They also received one Contingent Value Obligation for each share of Florida Progress stock, entitling them to payments in the event that four synthetic fuel plants achieve certain economic levels from 2001 to 2007. Data prior to merger are for CP&L only and are not comparable with Progress Energy data.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19.98 | 20.68 | 21.04 | 19.99 | 38.69 | 34.18 | 35.54 | 39.56 | 40.11 | 37.38 | *39.25* | *39.00* | Revenues per sh | *40.90* |
| 6.26 | 6.44 | 6.06 | 5.37 | 8.14 | 7.02 | 7.54 | 7.40 | 6.53 | 5.93 | *7.00* | *7.35* | "Cash Flow" per sh | *8.40* |
| 2.66 | 2.75 | 2.55 | 2.34 | 3.43 | 3.84 | 3.41 | 3.10 | 2.94 | 2.05 | *2.90* | *3.00* | Earnings per sh A | *3.30* |
| 1.90 | 1.96 | 2.02 | 2.08 | 2.14 | 2.18 | 2.26 | 2.32 | 2.38 | 2.42 | *2.45* | *2.47* | Div'd Decl'd per sh B†■ | *2.53* |
| 2.57 | 2.80 | 4.32 | 4.61 | 5.56 | 5.05 | 4.14 | 4.04 | 4.29 | 5.56 | *9.35* | *9.55* | Cap'l Spending per sh | *7.30* |
| 18.63 | 19.49 | 21.38 | 26.32 | 27.45 | 28.73 | 30.26 | 30.90 | 31.90 | 32.37 | *32.75* | *33.15* | Book Value per sh C | *35.05* |
| 151.34 | 151.34 | 159.60 | 206.09 | 218.73 | 232.43 | 246.00 | 247.00 | 252.00 | 256.00 | *260.00* | *264.00* | Common Shs Outst'g E | *274.00* |
| 13.6 | 15.9 | 15.2 | 15.3 | 12.4 | 11.9 | 12.4 | 14.1 | 14.8 | 21.62 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.0* |
| .78 | .83 | .87 | .99 | .64 | .65 | .71 | .74 | .79 | 1.17 | *Value Line* | | Relative P/E Ratio | *1.05* |
| 5.3% | 4.5% | 5.2% | 5.8% | 5.0% | 4.8% | 5.3% | 5.3% | 5.5% | 5.5% | *estimates* | | Avg Ann'l Div'd Yield | *4.9%* |
| 3024.1 | 3130.1 | 3357.6 | 4118.9 | 8461.5 | 7945.0 | 8743.0 | 9772.0 | 10108 | 9570 | *10200* | *10290* | Revenues ($mill) | *11200* |
| 388.3 | 399.2 | 382.3 | 369.9 | 695.1 | 815.2 | 818.1 | 763.5 | 727.0 | 514.0 | *760* | *790* | Net Profit ($mill) | *900* |
| 37.6% | 39.2% | 40.3% | 35.4% | -- | -- | -- | 13.1% | 13.1% | 28.4% | *28.0%* | *28.0%* | Income Tax Rate | *28.0%* |
| 1.3% | 1.7% | 3.0% | 5.6% | 2.6% | 1.0% | 3.4% | .8% | 1.8% | 1.4% | *1.0%* | *1.0%* | AFUDC % to Net Profit | *1.0%* |
| 45.6% | 46.5% | 46.6% | 51.6% | 60.9% | 59.0% | 56.1% | 55.2% | 56.2% | 51.3% | *51.5%* | *51.0%* | Long-Term Debt Ratio | *49.5%* |
| 53.2% | 52.4% | 52.5% | 47.6% | 38.5% | 40.4% | 43.4% | 44.3% | 43.3% | 48.1% | *48.0%* | *48.5%* | Common Equity Ratio | *50.0%* |
| 5293.8 | 5623.1 | 6500.6 | 11407 | 15580 | 16517 | 17162 | 17247 | 18577 | 17214 | *17735* | *18075* | Total Capital ($mill) | *18955* |
| 6293.5 | 6299.5 | 6764.8 | 10437 | 10915 | 10656 | 14434 | 14363 | 14442 | 15245 | *16605* | *17975* | Net Plant ($mill) | *20395* |
| 8.9% | 8.6% | 7.3% | 4.3% | 6.4% | 6.8% | 6.5% | 6.2% | 5.6% | 4.8% | *6.0%* | *6.0%* | Return on Total Cap'l | *6.5%* |
| 13.5% | 13.3% | 11.0% | 6.7% | 11.4% | 12.0% | 10.9% | 9.9% | 8.9% | 6.1% | *9.0%* | *9.0%* | Return on Shr. Equity | *9.5%* |
| 13.6% | 13.4% | 11.1% | 6.7% | 11.5% | 12.1% | 10.9% | 9.9% | 9.0% | 6.1% | *9.0%* | *9.0%* | Return on Com Equity D | *9.5%* |
| 3.9% | 4.0% | 2.5% | NMF | 4.3% | 5.0% | 3.7% | 2.6% | 1.7% | NMF | *1.5%* | *1.5%* | Retained to Com Eq | *2.5%* |
| 72% | 71% | 78% | 101% | 63% | 59% | 67% | 74% | 81% | 119% | *84%* | *82%* | All Div'ds to Net Prof | *76%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $10,201 mill. **Due in 5 Yrs** $3697 mill.
**LT Debt** $8436 mill. **LT Interest** $581 mill.
(LT interest earned: 2.2x)
**Pension Assets-12/06** $1.84 bill. **Oblig.** $2.12 bill.
**Pfd Stock** $92.8 mill. **Pfd Div'd** $4.5 mill.
921,814 shs. $4.00 to $5.44 cum. no par. callable from $101 to $110 per sh. Sinking funds began in 1984 and 1986, respectively.
**Common Stock** 259,000,000 shs.
**MARKET CAP: $12.3 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +.5 | 1.4 | -2.3 |
| Avg. Indust. Use (MWH) | 2394 | 2399 | 2328 |
| Avg. Indust. Revs. per KWH (¢) | 4.84 | 5.74 | 6.38 |
| Capacity at Peak (Mw) | 23878 | 24500 | 21322 |
| Peak Load, Summer (Mw) | 19711 | 21983 | 21717 |
| Annual Load Factor (%) | 61.3 | 55.0 | NA |
| % Change Customers (yr-end) | +2.2 | +3.1 | +2.0 |
| Fixed Charge Cov. (%) | 227 | 198 | 204 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 7.5% | 8.0% | *1.0%* |
| "Cash Flow" | 2.5% | .5% | *4.0%* |
| Earnings | 1.0% | -.5% | *3.5%* |
| Dividends | 3.0% | 2.5% | *1.0%* |
| Book Value | 6.5% | 5.0% | *1.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 2245 | 2408 | 2761 | 2358 | 9772 |
| 2005 | 2168 | 2295 | 3067 | 2578 | 10108 |
| 2006 | 2250 | 2316 | 2731 | 2273 | 9570 |
| 2007 | 2334 | 2406 | 3100 | *2360* | *10200* |
| 2008 | *2410* | *2480* | *2960* | *2440* | *10290* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .45 | .63 | 1.24 | .78 | 3.10 |
| 2005 | .43 | .03 | 1.85 | .64 | 2.94 |
| 2006 | .34 | .08 | 1.12 | .51 | 2.05 |
| 2007 | .61 | .51 | 1.21 | *.57* | *2.90* |
| 2008 | *.63* | *.52* | *1.25* | *.60* | *3.00* |

| Cal-endar | QUARTERLY DIVIDENDS PAID ■B† Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .56 | .56 | .56 | .56 | 2.24 |
| 2004 | .575 | .575 | .575 | .575 | 2.30 |
| 2005 | .59 | .59 | .59 | .59 | 2.36 |
| 2006 | .605 | .605 | .605 | .605 | 2.42 |
| 2007 | .61 | .61 | .61 | .61 | |

**BUSINESS:** Progress Energy, parent of CP&L Energy and Florida Progress, supplies electricity to portions of North Carolina, South Carolina, and Florida. Other operations include synthetic fuels, coal mining, wholesale generation, and financial services. Electric revenues: residential, 37%; commercial, 25%; industrial, 18%; other, 20%. Power costs: 43% of revs; labor costs: 14%. Fuel sources: gas/oil/coal, 50%; nuclear, 43%; hydro, 1%; purch. power, 6%. Has 11,600 employees. '06 depreciation rate: 2.7%. Est'd plant age: 8 years. Chairman, CEO, and President: William D. Johnson. Incorporated: North Carolina. Address: 411 Fayetteville Street, Raleigh, North Carolina 27602. Telephone: 1-800-662-7232. Internet: www.progress-energy.com.

**Progress Energy plans to add 12,500 megawatts (mw) of capacity by 2025.** For starters, the 500-mw gas-fired Hines 4 plant is scheduled to go on line next month at a cost of $327 million. Its location at the same site where three facilities are already operating will spread fixed costs over an additional unit. PGN has also begun major renovation at the Bartow station. Three plants are being converted from burning heavy oil to burning natural gas, and their combined output will be increased by 600 mw. The first two units are targeted to go on line in 2009, the third one year later. The project will cost $435 million. Too, the company is seeking approval to construct four diesel plants of 1,000 mw each. Additional generation will be built as the need arises. Meanwhile, the company is ramping up its energy-efficiency program to delay the need for the next coal-fired plant. These activities will require some long-term debt financing over the next few years.

**Rate adjustments in Florida are in the works.** Under a 2005 agreement with regulators, base rates will be increased $52 million when the Hines 4 plant begins operating. Furthermore, last year's storm-related surcharge to replenish the reserve fund has been extended through July, 2008. This will add $130 million to the fund. On the down side, the company has been ordered to refund $13.8 million to ratepayers for imprudent coal purchases in 2001 and 2005. The order has been appealed.

**A strong first half points to improved earnings in 2007.** The installation of 2.7 million "smart" meters will reduce yearly payroll by $24 million. Higher margins on energy sales, a 2% increase in kilowatt-hour sales, and lower income taxes are additional pluses. Despite an increase in nuclear plant downtime for refuelings, we estimate 2007 earnings will rise more than 40%, to $2.90 a share. The sale of non-utility businesses suggests steady, but modest, profit growth to 2010-2012.

**The yield is above the industry norm.** That reflects a probable slowdown in earnings growth and the likelihood that dividend hikes will be slower than they have been. All told, we rate PGN an average utility investment.

*Arthur H. Medalie* *November 30, 2007*

(A) EPS diluted. Next egs. report due late Jan. Excl. nonrecur.: '00, 69¢; '01, (75¢); '02, ($1.32); '03, (3¢); '05, (39¢). (B) Div'ds historically paid in early Feb., May, Aug, and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan avail. (C) Incl. def. charges in '06: $26.84/sh. (D) Rate Base: orig. cost. Rate allowed on common equity. In '88 in N.C.: 12.75%; in '88 in S.C.: 12.75%; in '02 in Fla.: rev. sharing incentive plan; earn. on '06 avg. com. eq.: 6.3%. Regul. Clim.: Avg. (E) In millions.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 5 |
| Earnings Predictability | 70 |

# SCANA CORP. NYSE-SCG

RECENT PRICE **41.99** | P/E RATIO **14.7** (Trailing: 16.4 / Median: 14.0) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **4.3%** | **VALUE LINE**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 28.6 | 29.9 | 37.3 | 32.6 | 31.1 | 30.0 | 32.1 | 35.7 | 39.7 | 43.7 | 42.4 | 45.5 |
| Low: | 25.3 | 23.4 | 27.9 | 21.1 | 22.0 | 24.3 | 23.5 | 28.1 | 32.8 | 36.6 | 36.9 | 32.9 |

**Target Price Range**
2010 | 2011 | 2012

TIMELINESS **4** Raised 8/10/07
SAFETY **2** Lowered 9/10/99
TECHNICAL **4** Lowered 11/2/07
BETA .85 (1.00 = Market)

**2010-12 PROJECTIONS**

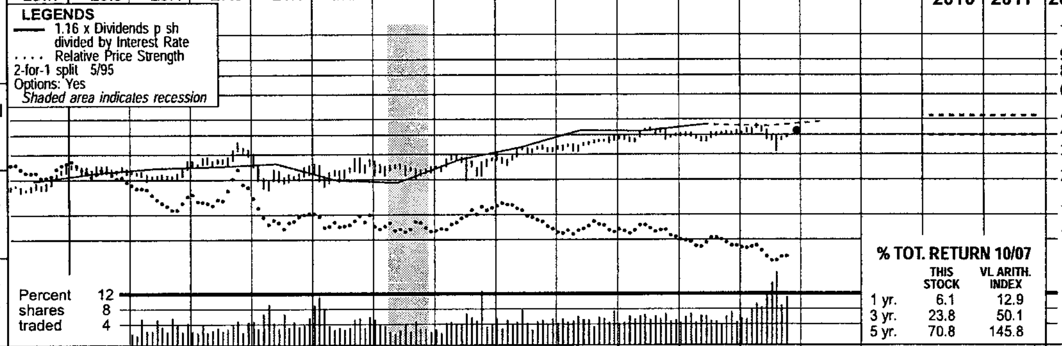
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+20%) | 8% |
| Low | 40 | (-5%) | 3% |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 |
| Options | 0 | 0 | 2 | 0 | 0 | 2 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 2 | 0 | 0 | 3 | 0 | 0 | 1 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 135 | 141 | 129 |
| to Sell | 107 | 108 | 111 |
| Hld's(000) | 48538 | 48063 | 50548 |




**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 6.1 | 12.9 |
| 3 yr. | 23.8 | 50.1 |
| 5 yr. | 70.8 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14.07 | 12.96 | 13.56 | 13.77 | 13.06 | 14.25 | 14.19 | 15.76 | 15.93 | 32.78 | 32.95 | 26.65 | 30.85 | 34.38 | 41.54 | 39.00 | *40.15* | *42.75* | Revenues per sh | *50.00* |
| 3.10 | 2.78 | 3.50 | 3.77 | 3.68 | 3.75 | 3.53 | 3.62 | 3.15 | 4.43 | 4.55 | 4.56 | 4.95 | 5.26 | 7.41 | 5.67 | *5.80* | *6.05* | "Cash Flow" per sh | *7.00* |
| 1.69 | 1.42 | 1.86 | 1.60 | 1.86 | 2.05 | 1.90 | 2.12 | 1.44 | 2.12 | 2.15 | 2.38 | 2.50 | 2.67 | 2.78 | 2.59 | *2.70* | *2.90* | Earnings per sh A | *3.25* |
| 1.31 | 1.34 | 1.37 | 1.41 | 1.44 | 1.47 | 1.51 | 1.54 | 1.32 | 1.15 | 1.20 | 1.30 | 1.38 | 1.46 | 1.56 | 1.68 | *1.76* | *1.82* | Div'd Decl'd per sh B ■ † | *2.00* |
| 2.93 | 3.16 | 3.46 | 4.21 | 3.09 | 2.34 | 2.45 | 2.87 | 2.37 | 3.28 | 4.99 | 6.41 | 6.94 | 4.84 | 3.37 | 4.50 | *6.40* | *7.45* | Cap'l Spending per sh | *5.25* |
| 12.62 | 13.23 | 14.30 | 14.69 | 15.00 | 15.86 | 16.66 | 16.86 | 20.27 | 19.40 | 20.95 | 19.64 | 20.82 | 21.69 | 23.28 | 24.32 | *25.40* | *26.50* | Book Value per sh C | *30.00* |
| 81.57 | 87.82 | 93.24 | 96.04 | 103.62 | 106.18 | 107.32 | 103.57 | 103.57 | 104.73 | 104.73 | 110.83 | 110.74 | 113.00 | 115.00 | 117.00 | *117.00* | *117.00* | Common Shs Outst'g D | *117.00* |
| 11.3 | 14.5 | 12.8 | 14.0 | 12.3 | 13.1 | 13.4 | 14.5 | 17.5 | 12.5 | 12.6 | 12.2 | 13.0 | 13.6 | 14.4 | 15.4 | *Bold figures are* | | Avg Ann'l P/E Ratio | *13.5* |
| .72 | .88 | .76 | .92 | .82 | .82 | .77 | .75 | 1.00 | .81 | .65 | .67 | .74 | .72 | .77 | .83 | *Value Line* | | Relative P/E Ratio | *.90* |
| 6.9% | 6.5% | 5.8% | 6.3% | 6.3% | 5.5% | 5.9% | 5.0% | 5.2% | 4.3% | 4.4% | 4.5% | 4.2% | 4.0% | 3.9% | 4.2% | *estimates* | | Avg Ann'l Div'd Yield | *4.5%* |

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1523.0 | 1632.0 | 1650.0 | 3433.0 | 3451.0 | 2954.0 | 3416.0 | 3885.0 | 4777.0 | 4563.0 | *4700* | *5000* | Revenues ($mill) | *5850* |
| 213.0 | 235.0 | 160.0 | 228.0 | 231.0 | 259.0 | 285.0 | 305.0 | 323.0 | 306.0 | *325* | *345* | Net Profit ($mill) | *385* |
| 32.8% | 35.8% | 41.0% | 38.2% | 34.9% | 32.2% | 31.5% | 32.5% | 32.5% | 26.5% | *33.5%* | *35.0%* | Income Tax Rate | *35.0%* |
| 6.1% | 6.8% | 4.4% | 3.9% | 11.3% | 13.5% | 10.5% | 8.5% | .9% | 2.6% | *7.0%* | *9.0%* | AFUDC % to Net Profit | *3.0%* |
| 44.5% | 45.9% | 40.8% | 57.4% | 53.9% | 55.7% | 57.1% | 55.4% | 51.4% | 50.9% | *50.0%* | *51.0%* | Long-Term Debt Ratio | *49.5%* |
| 50.8% | 49.4% | 54.8% | 40.3% | 43.8% | 42.1% | 40.8% | 42.6% | 46.6% | 47.2% | *48.5%* | *47.0%* | Common Equity Ratio | *49.0%* |
| 3522.0 | 3536.0 | 3829.0 | 5048.0 | 5006.0 | 5176.0 | 5646.0 | 5752.0 | 5739.0 | 6027.0 | *6155* | *6580* | Total Capital ($mill) | *7175* |
| 3648.0 | 3764.0 | 3829.0 | 4475.0 | 4803.0 | 5474.0 | 6417.0 | 6762.0 | 6734.0 | 7007.0 | *7395* | *7900* | Net Plant ($mill) | *8650* |
| 7.7% | 8.4% | 5.9% | 6.8% | 6.9% | 7.0% | 6.9% | 7.1% | 7.4% | 6.8% | *7.0%* | *7.0%* | Return on Total Cap'l | *7.0%* |
| 10.9% | 12.3% | 7.1% | 10.6% | 10.0% | 11.3% | 11.8% | 11.9% | 11.6% | 10.3% | *10.5%* | *10.5%* | Return on Shr. Equity | *10.5%* |
| 11.4% | 12.8% | 7.1% | 10.9% | 10.2% | 11.6% | 12.1% | 12.2% | 11.8% | 10.5% | *10.5%* | *11.0%* | Return on Com Equity E | *11.0%* |
| 2.4% | 3.4% | -- | 4.8% | 4.6% | 5.5% | 5.5% | 5.6% | 5.3% | 3.8% | *3.5%* | *4.0%* | Retained to Com Eq | *4.0%* |
| 80% | 74% | 99% | 57% | 56% | 54% | 55% | 55% | 56% | 65% | *66%* | *64%* | All Div'ds to Net Prof | *62%* |

**CAPITAL STRUCTURE as of 6/30/07**
**Total Debt** $3586.0 mill. **Due in 5 Yrs** $1658.0 mill.
**LT Debt** $2959.0 mill. **LT Interest** $176.0 mill.
(LT interest earned: 2.7x)
**Leases, Uncapitalized** Annual rentals $30.0 mill.
**Pension Assets-12/06** $912.5 mill. **Oblig.** $713.0 mill.
**Pfd Stock** $113.0 mill. **Pfd Div'd** $6.0 mill.
125,209 shs. 5% cum., $50 par., callable $52.50; 220,287 shs. 4.50% to 6.00% cum., $50 par, callable $50.50 to $51.00; 1,000,000 shs. 6.52% cum., $100 par, callable $100.00.
**Common Stock** 116,664,933 shs. as of 7/31/07
**MARKET CAP: $4.9 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +4.9 | +.9 | -1.4 |
| Avg. Indust. Use (MWH) | NA | 13249 | 12005 |
| Avg. Indust. Revs. per KWH (¢) | 4.32 | 4.82 | 5.16 |
| Capacity at Yearend (Mw) | 5776 | 5776 | 5749 |
| Peak Load, Summer (Mw) | 4574 | 4820 | 4747 |
| Annual Load Factor (%) | 60.2 | 57.3 | 57.5 |
| % Change Customers (yr-end) | +2.5 | +3.1 | +2.2 |
| Fixed Charge Cov. (%) | 264 | 190 | 261 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 11.0% | 7.0% | *4.5%* |
| "Cash Flow" | 5.0% | 8.5% | *2.5%* |
| Earnings | 4.0% | 7.0% | *3.5%* |
| Dividends | 1.0% | 5.0% | *4.0%* |
| Book Value | 4.5% | 2.5% | *4.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 1136 | 846.0 | 857.0 | 1046 | 3885.0 |
| 2005 | 1266 | 891.0 | 1127 | 1493 | 4777.0 |
| 2006 | 1389 | 944.0 | 1062 | 1168 | 4563.0 |
| 2007 | 1363 | 1007 | 1079 | *1251* | *4700* |
| 2008 | *1450* | *1100* | *1150* | *1300* | *5000* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .91 | .54 | .71 | .51 | 2.67 |
| 2005 | .89 | .36 | .88 | .65 | 2.78 |
| 2006 | .80 | .46 | .76 | .57 | 2.59 |
| 2007 | .73 | .47 | .79 | *.71* | *2.70* |
| 2008 | *.85* | *.50* | *.88* | *.67* | *2.90* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .325 | .345 | .345 | .345 | 1.36 |
| 2004 | .345 | .365 | .365 | .365 | 1.44 |
| 2005 | .365 | .39 | .39 | .39 | 1.54 |
| 2006 | .39 | .42 | .42 | .42 | 1.65 |
| 2007 | .42 | .44 | .44 | .44 | |

**BUSINESS:** SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 636,000 customers in South Carolina. Supplies gas and transmission service to 1.2 million customers in North and South Carolina and Georgia. Owns gas pipelines. Acquired PSNC Energy 2/00. Electric revenue breakdown, '06: residential, 40%; commercial, 31%; industrial, 17%; other, 12%. Generating sources, '06: coal, 66%; nuclear, 19%; oil & gas, 9%; hydro, 4%; purchased, 2%. Fuel costs: 63% of revenues. '06 reported deprec. rate: 3.2%. Has 5,700 employees. Chairman, President & CEO: William B. Timmerman. Incorporated: South Carolina. Address: 1426 Main St., Columbia, SC 29201-2845. Tel.: 803-217-9000. Internet: www.scana.com.

**SCANA's utility subsidiary in South Carolina has reached a settlement of its electric rate case.** South Carolina Electric & Gas had filed for a rate hike of $118 million (6.75%) based on an 11.75% return on equity. The utility, the commission's staff, and intervenor groups reached a settlement for a $76.9 million (4.4%) increase, based on an 11% ROE. The South Carolina commission must approve the agreement. Its decision is expected by mid-December, with new tariffs taking effect at the start of 2008. We think the settlement is very reasonable.

**The South Carolina commission has increased SCE&G's base gas rates.** The $4.6 million boost took effect in November. It was granted in accordance with a regulatory mechanism that allows the commission to raise the utility's gas rates (if necessary), without a full-blown rate case, to provide SCE&G with an opportunity to earn its allowed ROE of 10.25%.

**Earnings will probably increase in 2007,** despite the fact that they declined in the first nine months. The fourth-quarter comparison should be easy, since profits were weak a year ago due to mild weather and a settlement with the Federal Energy Regulatory Commission that reduced share net by $0.08. Our estimate is at the low end of SCANA's targeted range of $2.70-$2.85 a share.

**We look for higher profits in 2008.** We assume that the electric rate settlement in South Carolina is approved. Also, we assume normal weather conditions, and the first quarter of 2007 was milder than usual. SCANA should also benefit from customer growth at SCE&G and the company's gas utility subsidiary in North Carolina. Our earnings forecast is at the low end of management's guidance of $2.90-$3.05 a share.

**We expect a dividend hike at the board meeting in February.** We estimate that the directors will boost the annual disbursement by $0.06 a share. That's lower than recent increases due to the rising payout ratio. Even so, we wouldn't be shocked by a higher boost.

**SCANA stock is untimely but offers an above-average yield, even by utility standards.** Total-return potential to 2010-2012 is only average for a utility, however.

*Paul E. Debbas, CFA* *November 30, 2007*

(A) Excl. nonrec. gains (losses): '95, (16¢); '97, 16¢; '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '06: $9.90/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '05 in SC: 10.7% electric, 10.25% gas; in '06 in NC: none specified; earned on avg. com. eq., '06: 10.9%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 55 |
| Earnings Predictability | 95 |

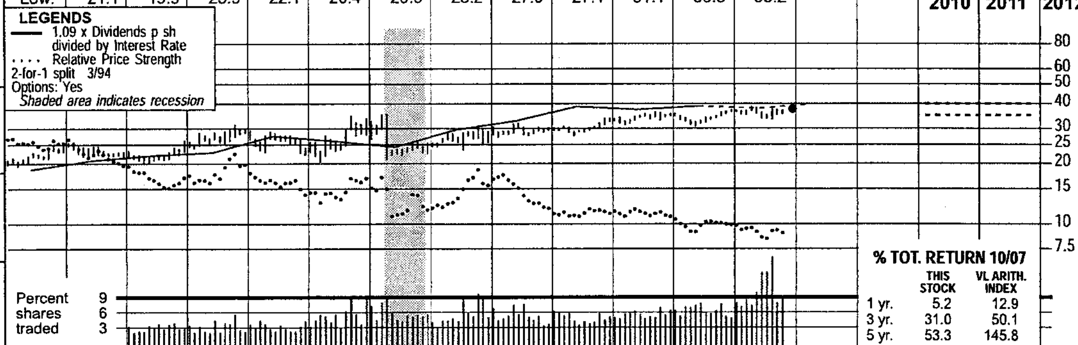
# SOUTHERN CO. NYSE-SO

RECENT PRICE 37.69 | P/E RATIO 17.7 (Trailing: 16.7; Median: 15.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS **3** Raised 8/4/06
SAFETY **1** Raised 6/3/05
TECHNICAL **3** Raised 8/24/07
BETA .70 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 25.9 | 26.3 | 31.6 | 29.6 | 35.0 | 35.7 | 31.1 | 32.0 | 34.0 | 36.5 | 37.4 | 38.9 |
| Low: | 21.1 | 19.9 | 23.9 | 22.1 | 20.4 | 20.9 | 23.2 | 27.0 | 27.4 | 31.1 | 30.5 | 33.2 |

Target Price Range 2010 | 2011 | 2012




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 40 | (+5%) | 6% |
| Low | 35 | (-5%) | 3% |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 |
| Options | 0 | 2 | 0 | 0 | 2 | 2 | 0 | 0 | 0 |
| to Sell | 0 | 2 | 0 | 0 | 2 | 2 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 292 | 250 | 279 |
| to Sell | 233 | 283 | 253 |
| Hld's(000) | 334197 | 330260 | 368747 |

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 5.2 | 12.9 |
| 3 yr. | 31.0 | 50.1 |
| 5 yr. | 53.3 | 145.8 |

In September, 2000, Southern spun off Mirant, its independent power marketing and trading subsidiary. Issuing 66.7 million shares, the company and Mirant shared $1.8 billion in gross proceeds. In April, 2001, management spun off the remaining 80.3% stake in Mirant to Southern investors; 0.4 of a common share in the subsidiary was distributed for each common share in the parent held. Mirant filed for Chapter 11 bankruptcy protection in July, 2003 and emerged from bankruptcy in January, 2006.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18.41 | 16.32 | 17.39 | 14.76 | 14.53 | 14.71 | 15.31 | 16.04 | 18.28 | 19.23 | *19.95* | *20.55* | Revenues per sh | *23.25* |
| 3.90 | 4.25 | 4.17 | 3.89 | 3.54 | 3.45 | 3.53 | 3.65 | 4.03 | 4.01 | *4.20* | *4.25* | "Cash Flow" per sh | *4.75* |
| 1.58 | 1.73 | 1.83 | 2.01 | 1.61 | 1.85 | 1.97 | 2.06 | 2.13 | 2.10 | *2.20* | *2.30* | Earnings per sh A | *2.50* |
| 1.30 | 1.34 | 1.34 | 1.34 | 1.34 | 1.36 | 1.39 | 1.42 | 1.48 | 1.54 | *1.60* | *1.66* | Div'd Decl'd per sh B ■ † | *1.85* |
| 2.71 | 2.87 | 3.84 | 3.26 | 3.74 | 3.79 | 2.72 | 2.84 | 3.20 | 4.01 | *5.10* | *5.75* | Cap'l Spending per sh | *4.25* |
| 14.08 | 14.02 | 13.82 | 15.67 | 11.42 | 12.15 | 13.13 | 13.86 | 14.41 | 15.23 | *16.30* | *17.35* | Book Value per sh C | *19.50* |
| 685.00 | 698.63 | 666.00 | 682.00 | 699.00 | 716.90 | 734.80 | 741.80 | 741.60 | 746.40 | *765.00* | *783.00* | Common Shs Outst'g D | *805.00* |
| 14.0 | 15.7 | 14.3 | 13.2 | 14.6 | 14.6 | 14.8 | 14.7 | 15.9 | 16.2 | *Bold figures are* | *Value Line* | Avg Ann'l P/E Ratio | *15.0* |
| .81 | .82 | .82 | .86 | .75 | .80 | .84 | .78 | .85 | .87 | *estimates* | | Relative P/E Ratio | *1.00* |
| 5.9% | 4.9% | 5.1% | 5.0% | 5.7% | 5.0% | 4.7% | 4.7% | 4.4% | 4.5% | | | Avg Ann'l Div'd Yield | *5.0%* |
| 12611 | 11403 | 11585 | 10066 | 10155 | 10549 | 11251 | 11902 | 13554 | 14356 | *15250* | *16100* | Revenues ($mill) | *18650* |
| 1245.0 | 1372.0 | 1457.0 | 1501.0 | 1306.0 | 1510.0 | 1602.1 | 1589.0 | 1621.0 | 1608.0 | *1730* | *1830* | Net Profit ($mill) | *2080* |
| 36.9% | 24.1% | 25.6% | 31.0% | 29.9% | 25.9% | 27.0% | 27.0% | 26.9% | 32.7% | *34.0%* | *35.0%* | Income Tax Rate | *35.0%* |
| 1.6% | 1.8% | 1.9% | 4.7% | 5.1% | 5.4% | 4.6% | 5.2% | 4.4% | 4.8% | *6.0%* | *7.0%* | AFUDC % to Net Profit | *5.0%* |
| 46.4% | 45.9% | 48.2% | 37.1% | 43.8% | 43.1% | 45.9% | 53.5% | 53.2% | 50.8% | *51.5%* | *52.0%* | Long-Term Debt Ratio | *54.0%* |
| 43.5% | 42.9% | 37.8% | 50.6% | 42.2% | 43.4% | 43.6% | 44.1% | 44.3% | 46.2% | *46.0%* | *45.5%* | Common Equity Ratio | *44.0%* |
| 22158 | 22817 | 24372 | 21147 | 18925 | 20086 | 22135 | 23288 | 24131 | 24618 | *27225* | *29925* | Total Capital ($mill) | *35700* |
| 23652 | 24124 | 24544 | 21622 | 23084 | 24642 | 27534 | 28361 | 29480 | 31092 | *33525* | *36500* | Net Plant ($mill) | *43400* |
| 7.1% | 7.6% | 7.8% | 8.5% | 8.2% | 8.6% | 8.4% | 8.1% | 8.2% | 8.2% | *7.5%* | *7.5%* | Return on Total Cap'l | *7.5%* |
| 10.5% | 11.1% | 11.5% | 11.3% | 12.3% | 13.2% | 13.4% | 14.7% | 14.4% | 13.3% | *13.0%* | *13.0%* | Return on Shr. Equity | *12.5%* |
| 11.2% | 12.2% | 13.6% | 12.3% | 14.0% | 15.1% | 14.8% | 14.9% | 14.9% | 13.8% | *13.5%* | *13.0%* | Return on Com Equity E | *13.0%* |
| 2.0% | 2.7% | 3.6% | 4.1% | 2.5% | 4.1% | 4.4% | 4.7% | 4.6% | 3.8% | *4.0%* | *3.5%* | Retained to Com Eq | *3.5%* |
| 84% | 81% | 77% | 71% | 85% | 76% | 73% | 69% | 70% | 73% | *72%* | *73%* | All Div'ds to Net Prof | *74%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $16823 mill. **Due in 5 Yrs** $4724 mill.
**LT Debt** $13817 mill. **LT Interest** $725.0 mill.
(LT interest earned: 3.9x)
**Leases, Uncapitalized** Annual rentals $135.0 mill.
**Pension Assets-12/06** $6.69 bill. **Oblig.** $5.49 bill.
**Pfd Stock** $766.3 mill. **Pfd Div'd** $41.8 mill.
Incl. 1 mill. shs. 4.20%-5.44% cum. sub. pfd. ($100 par); 12 mill. shs. 4.95%-5.83% cum. sub. pfd. ($1 par); 2 mill. shs. 6.0% noncum. sub. pfd. ($25 par); 1 mill. shs. 6.0% noncum. sub. pfd. ($100 par).
**Common Stock** 759,478,801 shs.
**MARKET CAP: $29 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.6 | +1.2 | +1.4 |
| Avg. Indust. Use (MWH) | 4029 | 3676 | 3670 |
| Avg. Indust. Revs. per KWH (¢) | 4.34 | 5.05 | 5.21 |
| Capacity at Yearend (Mw) | 38622 | 40502 | 41785 |
| Peak Load, Summer (Mw) | 34414 | 35050 | 35890 |
| Annual Load Factor (%) | 61.4 | 60.2 | 60.8 |
| % Change Customers (yr-end) | +1.5 | +1.2 | +1.7 |
| Fixed Charge Cov. (%) | 358 | 358 | 335 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 2.5% | 3.0% | *4.5%* |
| "Cash Flow" | 1.0% | -- | *3.5%* |
| Earnings | 2.5% | 3.0% | *3.0%* |
| Dividends | 2.0% | 2.0% | *4.0%* |
| Book Value | 1.0% | 1.0% | *5.0%* |

| Cal-endar | QUARTERLY REVENUES (mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 2732 | 3009 | 3441 | 2720 | 11902 |
| 2005 | 2787 | 3120 | 4358 | 3289 | 13554 |
| 2006 | 3063 | 3592 | 4549 | 3152 | 14356 |
| 2007 | 3409 | 3772 | 4832 | *3237* | *15250* |
| 2008 | *3600* | *3950* | *5100* | *3450* | *16100* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .45 | .48 | .87 | .26 | 2.06 |
| 2005 | .43 | .52 | .97 | .21 | 2.13 |
| 2006 | .35 | .52 | .99 | .25 | 2.10 |
| 2007 | .45 | .57 | 1.00 | *.18* | *2.20* |
| 2008 | *.40* | *.55* | *1.05* | *.30* | *2.30* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .343 | .343 | .35 | .35 | 1.39 |
| 2004 | .35 | .35 | .358 | .358 | 1.42 |
| 2005 | .358 | .373 | .373 | .373 | 1.48 |
| 2006 | .373 | .388 | .388 | .388 | 1.54 |
| 2007 | .388 | .403 | .403 | | |

**BUSINESS:** The Southern Company's four operating subsidiaries supply electricity to 4.3 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Revenue breakdown, '06: residential, 35%; commercial, 30%; industrial, 21%; other, 14%. Retail revenues by state: Georgia, 52%; Alabama, 34%; Florida, 8%; Mississippi, 6%. Also has competitive generation business. Generating sources, '06: coal, 67%; nuclear, 14%; oil & gas, 12%; hydro, 2%; purchased, 5%. Fuel costs: 40% of revenues. '06 reported deprec. rate: 3.0%. Has 26,100 employees. Chairman, President, and CEO: David M. Ratcliffe. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southernco.com.

**Southern Company's largest utility subsidiary has reached a settlement of its general rate case.** Georgia Power had asked the state regulators for a rate increase of $406.7 million based on a return of 12.5% on a 52.7% common-equity ratio. Since the utility will need additional rate relief for capital expenditures and operating expenses, its filing included an option for additional increases of $191 million at the start of 2009 and $45 million at the start of 2010. Georgia Power, the commission's staff, and other intervenors reached a settlement that calls for a general rate increase of $99.7 million at the start of 2008, plus an environmental cost recovery tariff that would average $222 million a year over a three-year period. The new rates would be based on an 11.25% return on a common-equity ratio of 52.7%, with an allowed ROE within a range of 10.25%-12.25%. The commission must still approve the agreement. Its order is expected in December, with new tariffs taking effect at the start of 2008.

**We expect earnings to increase this year and next.** The utilities are benefiting from kilowatt-hour sales growth of around 2% annually. Weather patterns in 2007 have been favorable, too. Although third-quarter earnings topped our estimate, we've trimmed our full-year estimate by $0.05 a share because the company expects to incur higher expenses for scheduled plant maintenance outages and it will take a $0.04 charge for the cancellation of a project. Our 2007 estimate includes $0.07 a share of income associated with Southern Company's synthetic fuel investments. Despite the cessation of the synfuel program at the end of 2007, we estimate an earnings increase in 2008, assuming that Georgia Power receives reasonable regulatory treatment.

**Finances are solid.** The capitalization ratios should remain sound, despite the company's need for financing through 2009 (driven by a capital budget that includes $4.6 billion of costs for environmental compliance). The fixed-charge coverage is well above the utility average, too.

**This high-quality stock offers an attractive yield.** It is above the utility mean. But 3- to 5-year total-return potential is only about average for a utility.

*Paul E. Debbas, CFA* *November 30, 2007*

(A) Diluted earnings. Excl. nonrecurring gain: '03, 6¢. '06 earnings don't add to total due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. def'd charges. In '06: $6.28/sh. (D) In mill., adj. for split. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on com. eq. (blended): 13.5%. Earned on avg. com. eq., '06: 14.3%. Regulatory Climate: AL, FL: Above Average; GA, MS: Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 25 |
| Earnings Predictability | 95 |

# TECO ENERGY, INC. NYSE-TE

RECENT PRICE 17.07 | P/E RATIO 14.0 (Trailing: 13.1; Median: 15.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Lowered 8/17/07

SAFETY 3 Lowered 3/7/03

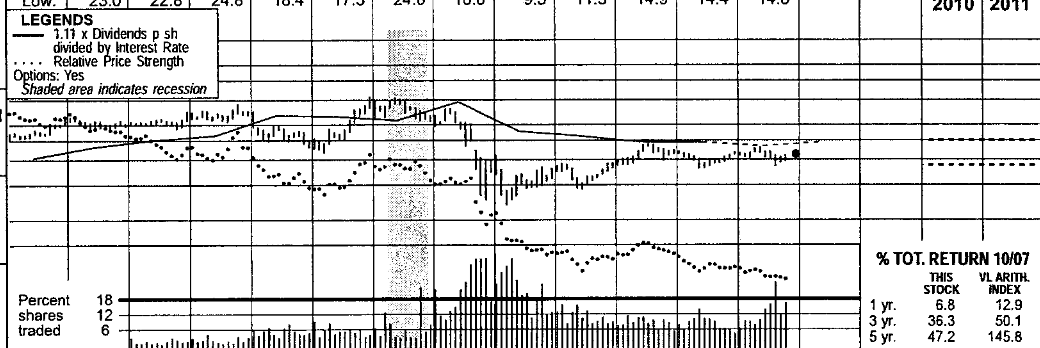
TECHNICAL 3 Raised 11/30/07

BETA .95 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 27.0 | 28.2 | 30.6 | 28.2 | 33.2 | 33.0 | 29.0 | 17.0 | 15.5 | 19.3 | 17.7 | 18.6 |
| Low: | 23.0 | 22.8 | 24.8 | 18.4 | 17.3 | 24.8 | 10.0 | 9.5 | 11.3 | 14.9 | 14.4 | 14.8 |

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.11 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




### 2010-12 PROJECTIONS

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 20 | (+15%) | 8% |
| Low | 15 | (-10%) | 2% |

### Insider Decisions

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 |
| Options | 1 | 0 | 1 | 0 | 0 | 1 | 2 | 0 | 0 |
| to Sell | 1 | 0 | 1 | 0 | 0 | 3 | 1 | 0 | 0 |

### Institutional Decisions

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 149 | 151 | 153 |
| to Sell | 121 | 139 | 138 |
| Hld's(000) | 118899 | 114475 | 118284 |

% TOT. RETURN 10/07

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 6.8 | 12.9 |
| 3 yr. | 36.3 | 50.1 |
| 5 yr. | 47.2 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.10 | 10.29 | 11.10 | 11.55 | 11.90 | 12.53 | 14.23 | 14.83 | 15.01 | 18.17 | 18.97 | 15.22 | 14.59 | 13.37 | 14.46 | 16.46 | **16.65** | **17.00** | Revenues per sh | **20.00** |
| 2.43 | 2.54 | 2.70 | 2.80 | 3.08 | 3.28 | 3.34 | 3.25 | 3.28 | 4.11 | 4.31 | 3.20 | 1.96 | 2.14 | 2.37 | 2.57 | **2.65** | **2.50** | "Cash Flow" per sh | **2.75** |
| 1.28 | 1.30 | 1.30 | 1.32 | 1.60 | 1.71 | 1.61 | 1.52 | 1.53 | 1.97 | 2.24 | 1.95 | d.08 | .71 | 1.00 | 1.17 | **1.35** | **1.15** | Earnings per sh A | **1.25** |
| .85 | .90 | .95 | 1.00 | 1.05 | 1.11 | 1.17 | 1.23 | 1.29 | 1.33 | 1.37 | 1.41 | .93 | .76 | .76 | .76 | **.78** | **.80** | Div'd Decl'd per sh B ■ | **.86** |
| 3.59 | 2.22 | 2.34 | 2.64 | 3.70 | 2.28 | 1.62 | 2.24 | 3.23 | 5.45 | 6.92 | 6.06 | 3.14 | 1.37 | 1.42 | 2.18 | **2.45** | **2.80** | Cap'l Spending per sh | **2.00** |
| 7.80 | 8.31 | 8.89 | 9.27 | 9.98 | 10.73 | 11.04 | 11.42 | 10.73 | 11.93 | 14.12 | 14.86 | 8.93 | 6.43 | 7.65 | 8.25 | **8.95** | **9.35** | Book Value per sh C | **10.75** |
| 114.22 | 114.97 | 115.62 | 116.92 | 116.96 | 117.60 | 130.90 | 132.00 | 132.10 | 126.30 | 139.60 | 175.80 | 187.80 | 199.70 | 208.20 | 209.50 | **210.50** | **211.50** | Common Shs Outst'g D | **215.00** |
| 13.9 | 15.1 | 17.9 | 15.0 | 13.8 | 14.3 | 15.4 | 17.8 | 14.2 | 11.9 | 12.9 | 11.0 | -- | 19.3 | 17.1 | 13.8 | *Bold figures are* | | Avg Ann'l P/E Ratio | **14.5** |
| .89 | .92 | 1.06 | .98 | .92 | .90 | .89 | .93 | .81 | .77 | .66 | .60 | -- | 1.02 | .91 | .75 | *Value Line* | | Relative P/E Ratio | **.95** |
| 4.8% | 4.6% | 4.1% | 5.0% | 4.7% | 4.5% | 4.7% | 4.5% | 5.9% | 5.7% | 4.8% | 6.6% | 7.4% | 5.5% | 4.4% | 4.7% | *estimates* | | Avg Ann'l Div'd Yield | **4.7%** |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $3534.5 mill. **Due in 5 Yrs** $1104.1 mill.
**LT Debt** $3454.4 mill. **LT Interest** $224.5 mill.
(LT interest earned: 2.5x)

**Leases, Uncapitalized** Annual rentals $28.1 mill.

**Pension Assets-12/06** $434.7 mill. **Oblig.** $569.9 mill.

**Pfd Stock** None

**Common Stock** 210,678,423 shs.
**as of 10/29/07**

**MARKET CAP: $3.6 billion (Mid Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1862.3 | 1958.1 | 1983.0 | 2295.1 | 2648.6 | 2675.8 | 2740.0 | 2669.1 | 3010.1 | 3448.1 | **3500** | **3600** | Revenues ($mill) | **4300** |
| 211.9 | 200.4 | 200.9 | 250.9 | 303.7 | 298.2 | d14.7 | 137.4 | 211.0 | 244.4 | **285** | **245** | Net Profit ($mill) | **270** |
| 30.9% | 28.8% | 30.2% | 6.9% | -- | -- | -- | 38.5% | 45.1% | 40.4% | **39.0%** | **39.0%** | Income Tax Rate | **39.0%** |
| .1% | -- | .9% | .9% | 3.0% | 4.4% | -- | .7% | -- | 1.6% | **2.0%** | **6.0%** | AFUDC % to Net Profit | **4.0%** |
| 42.8% | 45.9% | 46.0% | 47.7% | 48.3% | 50.5% | 72.4% | 75.1% | 70.0% | 65.0% | **64.5%** | **61.5%** | Long-Term Debt Ratio | **58.0%** |
| 57.2% | 54.1% | 54.0% | 52.3% | 51.7% | 39.7% | 27.6% | 24.9% | 30.0% | 35.0% | **35.5%** | **38.5%** | Common Equity Ratio | **42.0%** |
| 2524.9 | 2787.4 | 2625.6 | 2881.5 | 3814.1 | 6585.1 | 6070.3 | 5163.9 | 5300.9 | 4941.6 | **5350** | **5140** | Total Capital ($mill) | **5475** |
| 3236.5 | 3307.6 | 3627.8 | 3970.1 | 4838.3 | 5464.0 | 5679.0 | 4657.9 | 4566.9 | 4766.9 | **5025** | **5350** | Net Plant ($mill) | **5850** |
| 10.2% | 9.0% | 9.8% | 10.7% | 9.7% | 5.7% | 2.1% | 5.6% | 6.5% | 7.3% | **7.5%** | **7.0%** | Return on Total Cap'l | **7.0%** |
| 14.7% | 13.3% | 14.2% | 16.7% | 15.4% | 9.1% | NMF | 10.7% | 13.3% | 14.1% | **15.0%** | **12.5%** | Return on Shr. Equity | **11.5%** |
| 14.6% | 13.3% | 14.2% | 16.7% | 15.4% | 9.9% | NMF | 10.7% | 13.3% | 14.1% | **15.0%** | **12.5%** | Return on Com Equity E | **11.5%** |
| 4.5% | 2.6% | 2.3% | 5.5% | 6.1% | 3.2% | NMF | NMF | 3.3% | 5.0% | **6.5%** | **4.0%** | Retained to Com Eq | **3.5%** |
| 70% | 81% | 84% | 67% | 61% | 72% | NMF | 106% | 75% | 65% | **57%** | **69%** | All Div'ds to Net Prof | **68%** |

### ELECTRIC OPERATING STATISTICS

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +1.1 | +2.6 | +.6 |
| Avg. Indust'l Use (Mw) | NA | NA | NA |
| Avg. Indust'l Revs. per KWH (¢) | 6.49 | 6.44 | 7.66 |
| Capacity at Peak (Mw) | NA | 4423 | NA |
| Peak Load, Winter (Mw) | 3774 | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (avg.) | +2.4 | +2.6 | +2.8 |
| Fixed Charge Cov. (%) | NMF | 124 | 150 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 2.0% | -3.0% | 5.0% |
| "Cash Flow" | -2.5% | -9.5% | 2.5% |
| Earnings | -4.5% | -13.0% | 4.5% |
| Dividends | -3.0% | -10.5% | 2.0% |
| Book Value | -3.0% | -9.5% | 6.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 625.2 | 677.9 | 705.8 | 660.2 | 2669.1 |
| 2005 | 684.7 | 719.0 | 836.4 | 770.0 | 3010.1 |
| 2006 | 836.4 | 862.6 | 922.9 | 826.2 | 3448.1 |
| 2007 | 821.3 | 866.5 | 990.0 | **822.2** | **3500** |
| 2008 | **850** | **925** | **975** | **850** | **3600** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .17 | .09 | .28 | .17 | .71 |
| 2005 | .25 | .04 | .45 | .24 | 1.00 |
| 2006 | .26 | .29 | .38 | .23 | 1.17 |
| 2007 | .35 | .28 | .44 | **.28** | **1.35** |
| 2008 | **.25** | **.25** | **.40** | **.25** | **1.15** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .355 | .19 | .19 | .19 | .93 |
| 2004 | .19 | .19 | .19 | .19 | .76 |
| 2005 | .19 | .19 | .19 | .19 | .76 |
| 2006 | .19 | .19 | .19 | .19 | .76 |
| 2007 | .19 | .195 | .195 | .195 | |

**BUSINESS:** TECO Energy, Inc. is a holding company for Tampa Electric, which serves around 661,000 customers in west central Florida, and Peoples Gas (acq'd 6/97), which serves around 332,000 customers in Florida. TECO also mines and transports coal and has generation and distribution investments in Guatemala. Electric revenue breakdown, '06: residential, 46%; commercial, 29%; industrial, 8%; other, 17%. Generating sources, '06: coal, 54%; gas, 32%; oil, 1%; purchased, 13%. Fuel costs: 40% of revenues. '06 reported deprec. rate: 3.9%. Has 5,200 employees. Chairman & CEO: Sherrill W. Hudson. President & COO: John B. Ramil. Inc.: FL. Address: TECO Plaza, 702 N. Franklin St., Tampa, FL 33602. Tel.: 813-228-1111. Internet: www.tecoenergy.com.

**TECO Energy has reached an agreement to sell its barge transportation subsidiary,** TECO Transport. This operation generated a net profit of $22.8 million in 2006 and $27.0 million in the first nine months of 2007. TECO Transport fetched a price of $405 million, which will net the company $370 million-$380 million after taxes and transaction costs. TECO plans to use the proceeds to accelerate its goal of reducing debt by $500 million. The company expects to record a pretax gain of $225 million-$275 million on the sale, which we will *exclude* from our earnings presentation. The deal should close by the end of 2007. We won't adjust our figures to reflect the sale of TECO Transport until after it has been completed, but we figure the transaction will be slightly dilutive. Even so, we think the sale makes sense because it will enable the company to strengthen its balance sheet.

**The end of the synthetic fuel program is likely to result in an earnings decline in 2008.** Through hedging, TECO locked in a profit of $65 million ($0.31 a share) from its synfuel investments. Since the synfuel program will cease at yearend, the company will record no such income in 2008. Note that we have boosted our share-earnings estimates for 2007 and 2008 by a nickel each year because depreciation is likely to wind up lower than we had estimated. TECO hasn't provided earnings guidance for 2008 and won't do so until early next year.

**Tampa Electric has decided not to build a coal gasification plant to meet its 2013 power needs.** Uncertainty about changing environmental regulations and the rising cost of the project induced the company to look for alternative sources of power generation. Thus, our projection for capital spending in the 2010-2012 period is much lower than in our last report, in late August. For the time being, Tampa Electric plans to add peaking units in 2009 and 2010.

**This stock's main appeal is its high yield.** It is about a percentage point above the norm for dividend-paying utilities. We project just modest dividend growth over the 3- to 5-year period, however, so total-return potential over that time is only around average, by utility standards.

*Paul E. Debbas, CFA* *November 30, 2007*

(A) Diluted earnings. Excl. nonrecurring losses: '97, 6¢; '99, 11¢; '03, $4.97; gains (loss) on disc. ops.: '04, (77¢); '05, 31¢; '06, 1¢; '07, 7¢. '05 EPS don't add due to change in shares, '06 due to rounding. Next earnings report due early Feb. (B) Div'ds paid in late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '06: $1.80/sh. (D) In millions. (E) Rate base: Net orig. cost. Allowed return on com. eq. in '00 (elec.): 10.75%-12.75%; in '02 (gas): 10.25%-12.25%; earned on avg. com. eq., '06: 14.7%. Regulat. Climate: Above Avg.

| | |
|---|---|
| Company's Financial Strength | B |
| Stock's Price Stability | 80 |
| Price Growth Persistence | 10 |
| Earnings Predictability | 30 |

# UIL HOLDINGS NYSE-UIL

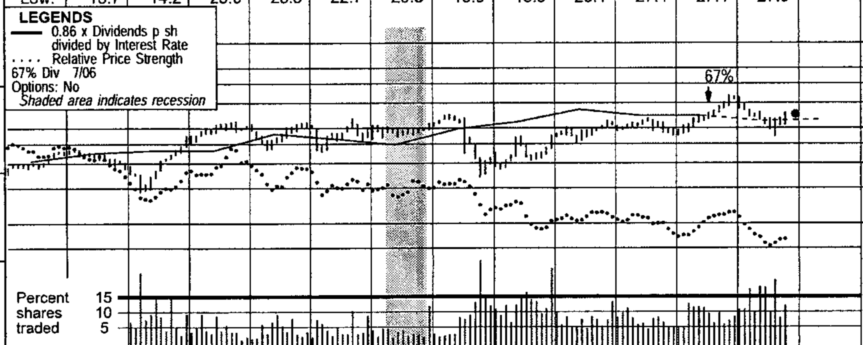
RECENT PRICE 35.09 | P/E RATIO 18.5 (Trailing: 21.9 / Median: 15.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 3 Raised 11/16/07
SAFETY 3 Lowered 12/6/02
TECHNICAL 2 Raised 11/30/07
BETA .95 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 24.0 | 27.6 | 32.5 | 32.2 | 33.6 | 31.8 | 35.3 | 27.6 | 32.8 | 33.7 | 43.8 | 43.0 | |
| Low: | 18.7 | 14.2 | 25.0 | 23.3 | 22.7 | 26.3 | 16.9 | 18.5 | 25.1 | 27.4 | 27.4 | 27.0 | |

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 0.86 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
67% Div 7/06
Options: No
Shaded area indicates recession




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 40 | (+15%) | 8% |
| Low | 25 | (-30%) | -2% |

**Insider Decisions**

| | D | J | F | M | A | M | J | J | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |

**Institutional Decisions**

| | 4Q2006 | 1Q2007 | 2Q2007 |
|---|---|---|---|
| to Buy | 82 | 73 | 57 |
| to Sell | 34 | 51 | 66 |
| Hld's(000) | 12105 | 12263 | 12276 |

**% TOT. RETURN 10/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -7.1 | 12.9 |
| 3 yr. | 32.1 | 50.1 |
| 5 yr. | 160.5 | 145.8 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 29.00 | 28.53 | 27.82 | 27.97 | 29.38 | 30.89 | 30.64 | 29.34 | 29.01 | 37.54 | 46.15 | 47.55 | 40.39 | 45.87 | 49.88 | 34.03 | *38.10* | *42.30* | Revenues per sh | *52.25* |
| 4.79 | 4.90 | 4.90 | 4.77 | 4.91 | 4.81 | 5.40 | 5.34 | 4.67 | 5.53 | 6.61 | 5.89 | 4.69 | 4.37 | 4.13 | 4.65 | *5.00* | *5.85* | "Cash Flow" per sh | *7.40* |
| 1.93 | 1.90 | 1.88 | 1.91 | 2.18 | 1.90 | 1.96 | 1.80 | 2.23 | 2.56 | 2.53 | 1.85 | 1.24 | 1.54 | 1.30 | 1.86 | *1.85* | *1.95* | Earnings per sh A | *2.15* |
| 1.46 | 1.54 | 1.60 | 1.66 | 1.69 | 1.73 | 1.73 | 1.73 | 1.73 | 1.73 | 1.73 | 1.73 | 1.73 | 1.73 | 1.73 | 1.73 | *1.73* | *1.73* | Div'd Decl'd per sh B ■ | *1.73* |
| 2.72 | 2.84 | 4.04 | 2.69 | 2.53 | 2.01 | 1.44 | 1.63 | 1.48 | 2.31 | 2.01 | 2.41 | 2.19 | 2.04 | 2.25 | 3.09 | *10.15* | *5.50* | Cap'l Spending per sh | *3.75* |
| 17.30 | 18.07 | 18.03 | 18.23 | 18.72 | 18.72 | 18.94 | 19.05 | 19.55 | 20.42 | 21.25 | 20.28 | 20.65 | 22.84 | 22.39 | 18.53 | *18.70* | *19.05* | Book Value per sh C | *19.95* |
| 23.22 | 23.39 | 23.47 | 23.48 | 23.50 | 23.50 | 23.18 | 23.39 | 23.44 | 23.46 | 23.53 | 23.79 | 23.86 | 24.01 | 24.32 | 24.86 | *25.20* | *25.40* | Common Shs Outst'g E | *26.60* |
| 10.6 | 11.9 | 13.6 | 10.5 | 9.3 | 11.4 | 10.1 | 16.3 | 12.6 | 10.8 | 11.5 | 15.0 | 18.0 | 18.7 | 23.5 | 18.7 | *Bold figures are* | | Avg Ann'l P/E Ratio | *15.0* |
| .68 | .72 | .80 | .69 | .62 | .71 | .58 | .85 | .72 | .70 | .59 | .82 | 1.03 | .99 | 1.25 | 1.01 | *Value Line* | | Relative P/E Ratio | *1.00* |
| 7.2% | 6.8% | 6.2% | 8.2% | 8.3% | 8.0% | 8.8% | 5.9% | 6.2% | 6.2% | 5.9% | 6.2% | 7.7% | 6.0% | 5.7% | 5.0% | *estimates* | | Avg Ann'l Div'd Yield | *5.4%* |

**CAPITAL STRUCTURE as of 6/30/07**
**Total Debt** $528.6 mill. **Due in 5 Yrs.** $337.4 mill.
**LT Debt** $404.3 mill. **LT Interest** $21.5 mill.
(LT interest earned: 3.3x)
**Leases, Uncapitalized:** Ann. rentals $13.4 mill.

**Pension Assets-12/06** $317 mill. **Oblig.** $362 mill.

**Pfd Stock** None

**Common Stock** 25,160,004 shs. as of 8/1/07

**MARKET CAP: $875 million (Small Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 710.3 | 686.2 | 680.0 | 880.9 | 1085.8 | 1131.0 | 963.7 | 1101.3 | 1213.1 | 846.0 | *960* | *1075* | Revenues ($mill) | *1390* |
| 45.8 | 42.2 | 52.2 | 59.9 | 59.4 | 44.0 | 29.5 | 36.9 | 31.4 | 45.4 | *46.0* | *49.0* | Net Profit ($mill) | *57.0* |
| 47.4% | 56.0% | 56.0% | 44.5% | 44.8% | 45.2% | 53.1% | 45.4% | 44.1% | 31.2% | *31.0%* | *31.0%* | Income Tax Rate | *31.0%* |
| 3.5% | 1.1% | 4.3% | 4.4% | 3.2% | 5.1% | 8.5% | 1.1% | 9.0% | 8.0% | *6.0%* | *6.0%* | AFUDC % to Net Profit | *3.0%* |
| 57.3% | 57.7% | 50.5% | 52.2% | 49.9% | 45.0% | 50.1% | 47.2% | 47.2% | 47.0% | *49.5%* | *50.0%* | Long-Term Debt Ratio | *49.5%* |
| 38.0% | 37.7% | 44.6% | 47.8% | 50.1% | 55.0% | 49.9% | 52.8% | 52.8% | 53.0% | *50.5%* | *50.0%* | Common Equity Ratio | *50.5%* |
| 1154.8 | 1180.8 | 1026.5 | 1001.3 | 998.6 | 877.8 | 988.2 | 1039.6 | 1031.5 | 869.2 | *930* | *965* | Total Capital ($mill) | *1050* |
| 1273.6 | 1226.4 | 521.5 | 550.7 | 546.4 | 517.1 | 548.8 | 563.9 | 592.1 | 647.0 | *825* | *870* | Net Plant ($mill) | *810* |
| 6.7% | 5.4% | 7.1% | 7.9% | 8.1% | 7.3% | 4.3% | 4.5% | 4.1% | 6.5% | *6.0%* | *6.5%* | Return on Total Cap'l | *6.5%* |
| 9.3% | 8.4% | 10.3% | 12.5% | 11.9% | 9.1% | 6.0% | 6.7% | 5.8% | 9.9% | *9.5%* | *10.0%* | Return on Shr. Equity | *10.5%* |
| 10.4% | 9.4% | 11.4% | 12.5% | 11.9% | 9.1% | 6.0% | 6.7% | 5.8% | 9.9% | *9.5%* | *10.0%* | Return on Com Equity D | *10.5%* |
| 1.2% | .4% | 2.5% | 4.0% | 3.8% | .6% | NMF | NMF | NMF | NMF | *.5%* | *1.0%* | Retained to Com Eq | *2.0%* |
| 89% | 96% | 78% | 68% | 68% | 93% | NMF | 112% | NMF | 93% | *93%* | *89%* | All Div'ds to Net Prof | *80%* |

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.3 | +2.6 | -3.1 |
| Avg. Indust. Use (MWH) | 639 | 665 | 657 |
| Avg. Indust. Revs. per KWH (¢) | 9.13 | 9.70 | 10.2 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | -.1 | Nil | Nil |
| Fixed Charge Cov. (%) | 375 | 263 | 323 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 4.0% | 3.0% | *3.0%* |
| "Cash Flow" | -1.0% | -5.0% | *9.0%* |
| Earnings | -2.5% | -8.5% | *5.5%* |
| Dividends | -- | -- | *Nil* |
| Book Value | 1.5% | 1.0% | *-1.0%* |

**QUARTERLY REVENUES ($ mill.)**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 249.4 | 260.7 | 323.4 | 267.8 | 1101.3 |
| 2005 | 278.5 | 279.9 | 369.4 | 285.3 | 1213.1 |
| 2006 | 200.3 | 199.8 | 261.1 | 184.8 | 846.0 |
| 2007 | 274.6 | 216.7 | 267.9 | *200.8* | *960* |
| 2008 | *300* | *240* | *310* | *225* | *1075* |

**EARNINGS PER SHARE A**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .24 | .43 | .68 | .19 | 1.54 |
| 2005 | .13 | .14 | .77 | .26 | 1.30 |
| 2006 | .15 | .42 | 1.21 | .08 | 1.86 |
| 2007 | .22 | .38 | .92 | *.33* | *1.85* |
| 2008 | *.22* | *.43* | *1.00* | *.30* | *1.95* |

**QUARTERLY DIVIDENDS PAID B ■**

| Cal-endar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .432 | .432 | .432 | .432 | 1.73 |
| 2004 | .432 | .432 | .432 | .432 | 1.73 |
| 2005 | .432 | .432 | .432 | .432 | 1.73 |
| 2006 | .432 | .432 | .432 | .432 | 1.73 |
| 2007 | .432 | .432 | .432 | .432 | |

**BUSINESS:** UIL Holdings, parent of The United Illuminating Company, provides electricity to 320,000 customers in largely urban and suburban southern Connecticut. Revenue distribution: resid, 46%; commer, 41%; indust, 11%; other, 2%. Largest industrial customers: primary metals, fabricated metal products, transportation equipment. 2004, sold American Payment Systems. 2006, sold Xcelecom. Fuel costs: 49% of revenues; labor costs, 13%. '06 deprec. rate: 3.8%. Has 920 employees. Non-Executive Chairman: F. Patrick McFadden. Chief Executive Officer & President: James P. Torgerson. Incorporated: Connecticut. Address: 157 Church Street, P.O. Box 1564, New Haven, Connecticut 06506-0901. Tel.: 203-499-2394. Internet: www.uil.com.

**UIL Holdings' major project is construction of a 69-mile transmission line.** The company and Northeast Utilities are jointly building a 345-kilovolt line between Middletown and Norwalk, Connecticut to strengthen the weak grid in the southwestern part of the state. UIL will have a 20% ownership in the facility. Since 24 miles will have to be built underground to satisfy demands of towns and property owners along the route, the initial cost of $600 million rose to $1.3 billion. Work is well under way, and a new substation is nearly finished. Upon completion in late 2009, the project will not only serve the two owners but will supply power to other New England utilities. Regulation permits the company to recover 50% of prudently incurred costs as building progresses. The balance will be recouped through rate filings. In the early stages, UIL will finance its share of the cost internally, later with debt.

**The company seeks to build a gas-fired peaking plant.** The utility sold all of its generating facilities in 2000 when state law allowed consumers to choose their energy supplier. Pursuant to a 2007 law that permits utilities to build peaking units, UIL and NRG Energy plan to submit a proposal for a new peaking plant. If regulatory approval is granted, the company would recover the cost of building on a cost-of-service basis, and would earn a reasonable return on its investment. Re-entry into the generating business would offer UIL new opportunities.

**Earnings may show no progress this year.** The company will benefit from improved pricing, higher rates of $4.3 million, and recovery of work on the transmission system. But an IRS ruling on accumulated deferred investment tax credits that boosted third-quarter 2006 earnings by $0.26 a share will negate these positives. For now, we estimate 2007 earnings of $1.85 a share. A $10.3 million rate hike effective next January points to improved results next year.

**These shares have an even balance of pluses and minuses.** The year-ahead yield is more than a full percentage point above the industry norm. But a high payout ratio suggests no dividend increase in our 3- to 5-year timeframe.

*Arthur H. Medalie* *November 30, 2007*

(A) EPS basic. Excl. nonrecur. gains (losses): '91, 27¢; '92, 35¢; '93, (34¢); '94, (6¢); '96, 17¢; '00, net 4¢; '03, (26¢); '04, $2.14; '06, ($5.07). Next egs. report due late Jan.
(B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. & regul. assets. In '06: 77¢/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '06: 9.75%. Earned on average common equity in '06: 9.0%. Regul. Clim.: Below Average. (E) In millions.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 80 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 60 |

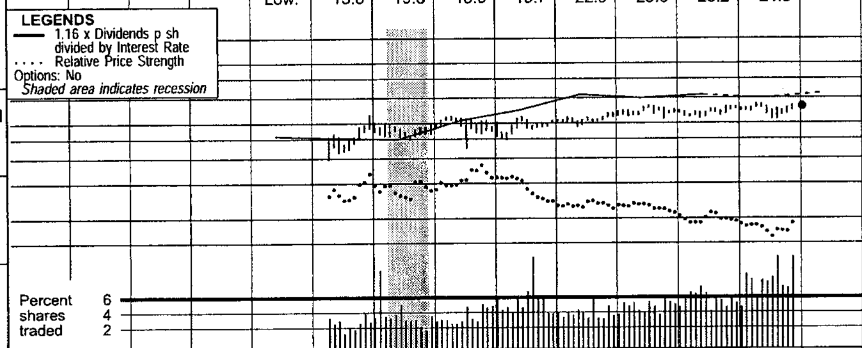
# VECTREN CORP. NYSE-VVC

RECENT PRICE **29.11** | P/E RATIO **15.7** (Trailing: 16.4; Median: NMF) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **4.5%** | VALUE LINE

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| High: | 26.5 | 24.4 | 26.1 | 26.1 | 27.1 | 29.5 | 29.3 | 30.5 | |
| Low: | 15.8 | 19.8 | 18.0 | 19.7 | 22.9 | 25.0 | 25.2 | 24.8 | |

**Target Price Range**
2010 | 2011 | 2012

**TIMELINESS** 2 Raised 12/28/07
**SAFETY** 2 Lowered 1/5/01
**TECHNICAL** 3 Raised 8/31/07
**BETA** .90 (1.00 = Market)




**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 35 | (+20%) | 9% |
| Low | 25 | (-15%) | 1% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 |
| Options | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 106 | 108 | 79 |
| to Sell | 55 | 76 | 104 |
| Hld's(000) | 40427 | 42063 | 43375 |

**% TOT. RETURN 11/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 7.5 | 3.0 |
| 3 yr. | 28.2 | 31.3 |
| 5 yr. | 62.1 | 107.6 |

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren. Data prior to the merger are pro forma.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | -- | 16.88 | 26.84 | 32.05 | 26.53 | 21.00 | 22.26 | 26.62 | 26.83 | *28.70* | *30.25* | Revenues per sh | *37.40* |
| -- | -- | 2.87 | 2.88 | 2.89 | 3.43 | 3.17 | 3.27 | 3.87 | 3.69 | *4.15* | *4.45* | "Cash Flow" per sh | *5.15* |
| -- | -- | 1.48 | 1.17 | 1.08 | 1.68 | 1.56 | 1.42 | 1.81 | 1.44 | *1.85* | *1.95* | Earnings per sh A | *2.05* |
| -- | -- | .95 | .98 | 1.03 | 1.07 | 1.11 | 1.15 | 1.19 | 1.23 | *1.27* | *1.31* | Div'd Decl'd per sh B■† | *1.43* |
| -- | -- | -- | 2.67 | 3.48 | 3.22 | 3.12 | 3.66 | 3.04 | 3.70 | *3.85* | *3.85* | Cap'l Spending per sh | *3.65* |
| -- | -- | 11.55 | 11.91 | 12.53 | 12.79 | 14.18 | 14.42 | 15.01 | 15.43 | *16.80* | *17.50* | Book Value per sh C | *19.55* |
| -- | -- | 61.47 | 61.42 | 67.70 | 68.01 | 75.60 | 75.90 | 76.19 | 76.10 | *80.80* | *81.00* | Common Shs Outst'g D | *81.60* |
| -- | -- | -- | 17.4 | 20.3 | 14.2 | 14.8 | 17.6 | 15.1 | 18.9 | Bold figures are Value Line estimates | | Avg Ann'l P/E Ratio | *14.5* |
| -- | -- | -- | 1.13 | 1.04 | .78 | .84 | .93 | .80 | 1.02 | | | Relative P/E Ratio | *.95* |
| -- | -- | -- | 4.8% | 4.7% | 4.5% | 4.8% | 4.6% | 4.4% | 4.5% | | | Avg Ann'l Div'd Yield | *4.8%* |
| -- | -- | 1037.4 | 1648.7 | 2170.0 | 1804.3 | 1587.6 | 1689.8 | 2028.0 | 2041.6 | *2320* | *2450* | Revenues ($mill) | *3050* |
| -- | -- | 90.8 | 72.0 | 73.1 | 114.0 | 111.2 | 108.0 | 136.8 | 108.8 | *150* | *160* | Net Profit ($mill) | *165* |
| -- | -- | 33.6% | 32.2% | 20.3% | 25.4% | 25.3% | 26.5% | 24.4% | 21.8% | *22.0%* | *22.0%* | Income Tax Rate | *22.0%* |
| -- | -- | -- | -- | 7.7% | 4.6% | 4.5% | 3.0% | 1.4% | 3.8% | *4.0%* | *4.0%* | AFUDC % to Net Profit | *3.0%* |
| -- | -- | 40.0% | 45.8% | 54.4% | 52.3% | 50.0% | 48.1% | 51.2% | 50.7% | *47.0%* | *48.0%* | Long-Term Debt Ratio | *48.5%* |
| -- | -- | 58.4% | 53.0% | 45.5% | 47.7% | 50.0% | 51.8% | 48.8% | 49.3% | *53.0%* | *52.0%* | Common Equity Ratio | *51.5%* |
| -- | -- | 1215.8 | 1380.6 | 1863.1 | 1824.4 | 2144.7 | 2111.5 | 2341.3 | 2382.2 | *2565* | *2725* | Total Capital ($mill) | *3105* |
| -- | -- | 1336.3 | 1555.8 | 1595.0 | 1648.1 | 2003.7 | 2156.2 | 2251.9 | 2385.5 | *2520* | *2625* | Net Plant ($mill) | *2795* |
| -- | -- | 8.6% | 6.1% | 5.5% | 7.7% | 6.6% | 6.4% | 7.2% | 6.0% | *7.0%* | *7.0%* | Return on Total Cap'l | *7.0%* |
| -- | -- | 12.5% | 9.6% | 8.6% | 13.1% | 10.4% | 9.9% | 12.0% | 9.3% | *11.0%* | *11.0%* | Return on Shr. Equity | *10.5%* |
| -- | -- | 12.6% | 9.7% | 8.5% | 13.1% | 10.4% | 9.9% | 12.0% | 9.3% | *11.0%* | *11.0%* | Return on Com Equity E | *10.5%* |
| -- | -- | 4.8% | 1.5% | .3% | 4.8% | 3.0% | 1.9% | 4.0% | 1.3% | *3.5%* | *3.5%* | Retained to Com Eq | *3.0%* |
| -- | -- | 63% | 85% | 96% | 63% | 71% | 81% | 66% | 86% | *69%* | *67%* | All Div'ds to Net Prof | *70%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $1732.8 mill. **Due in 5 Yrs** $822.0 mill.
**LT Debt** $1208.3 mill. **LT Interest** $68.1 mill.
(LT interest earned: 3.6x)

**Pension Assets-12/06** $185.0 mill. **Oblig.** $255.4 mill.

**Pfd Stock** None

**Common Stock** 76,517,056 shs. **as of 10/31/07**
**MARKET CAP: $2.2 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +1.5 | +3.5 | -3.1 |
| Avg. Indust. Use (MWH) | 23469 | 24074 | 23582 |
| Avg. Indust. Revs. per KWH (¢) | 4.24 | 4.64 | 4.99 |
| Capacity at Peak (Mw) | 1507 | 1534 | 1517 |
| Peak Load, Summer (Mw) | 1222 | 1291 | 1300 |
| Annual Load Factor (%) | 69.0 | 66.8 | 74.0 |
| % Change Customers (yr-end) | +2.6 | +.6 | +1.1 |
| Fixed Charge Cov. (%) | 262 | 256 | 226 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | -- | -- | 7.0% |
| "Cash Flow" | -- | 4.5% | 6.0% |
| Earnings | -- | 4.5% | 4.5% |
| Dividends | -- | 4.0% | 3.0% |
| Book Value | -- | 4.5% | 4.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 645.3 | 276.7 | 254.4 | 513.4 | 1689.8 |
| 2005 | 677.2 | 326.2 | 310.8 | 713.8 | 2028.0 |
| 2006 | 774.5 | 317.5 | 340.5 | 609.1 | 2041.6 |
| 2007 | 834.0 | 421.7 | 381.4 | *682.9* | *2320* |
| 2008 | *870* | *420* | *420* | *740* | *2450* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .72 | .04 | .13 | .53 | 1.42 |
| 2005 | .74 | .18 | .22 | .67 | 1.81 |
| 2006 | .76 | .06 | .16 | .46 | 1.44 |
| 2007 | .88 | .21 | .22 | *.54* | *1.85* |
| 2008 | *.90* | *.20* | *.20* | *.65* | *1.95* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■† Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2003 | .275 | .275 | .275 | .285 | 1.11 |
| 2004 | .285 | .285 | .285 | .295 | 1.15 |
| 2005 | .295 | .295 | .295 | .305 | 1.19 |
| 2006 | .305 | .305 | .305 | .315 | 1.23 |
| 2007 | .315 | .315 | .315 | .325 | |

**BUSINESS:** Vectren is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base of 1,136,000. 2006 Elect. (gas) revs: resid., 30% (67%); commer., 24% (27%); indust., 32% (5%); other, 14% (1%). Revenue sources: Elect., 20%; Gas, 80%. Fuel costs: elect., 37%; gas, 69%. Also provides energy-related products and services and has an investment subsidiary. Est'd plant age: electric, 10 years. '06 deprec. rate: 3.7%. Has 1,975 employees. Chairman & CEO: Niel C. Ellerbrook. President: Carl Chapman. Inc.: IN. Address: 20 Northwest 4th St., Evansville, Indiana 47741. Tel.: 812-465-5300. Internet: www.vectren.com.

**Vectren's construction budget will require external financing through 2010.** A large portion of the outlays is needed to comply with the U.S. Environmental Protection Agency's requirements. VVC and Alcan Aluminum, joint owners in the Warrick coal-fired station, are spending $300 million to reduce sulfur dioxide emissions at all four units by 98%. VVC's share of the cost will be $70 million. The company will also enhance the efficiency of existing scrubbers at the Culley 2 and 3 coal burners and will upgrade the infrastructure. All told, management plans capital spending of $300 million annually for the next three years. Since internally generated cash won't fully cover these costs, some external financing will be needed to close the gap.

**The company has applied for higher rates in two jurisdictions.** Last May, it filed for increased gas base rates of $41 million in its northern Indiana territory to recover costs of maintaining and expanding the 12,000-mile distribution and storage system. An order on the petition is expected in the second quarter of 2008. In Ohio, VVC issued a pre-filing notice in September, indicating it planned to request a $29 million hike for its gas distribution business. The increase is needed to recoup the cost of operating and expanding the 5,200-mile system that serves a 17-county area in west-central Ohio. An order here is due late next year.

**Earnings may post a record high in 2007.** Electric and gas margins are up, and environmental outlays are being recovered on a timely basis. What's more, a rate hike in southern Indiana will help fourth-quarter results. Too, the ProLiance subsidiary is benefiting from increased gas storage capacity. Our 2007 earnings estimate of $1.85-a-share excludes expected profits of $0.12 a share from synfuel operations, which have been classified as discontinued. Orders on two outstanding rate requests suggest further improvement in 2008. The stock is timely.

**The yield is almost a full percentage point above the industry norm.** And dividend growth prospects to 2010-2012 exceed those of the group. Income-oriented investors might consider these good-quality shares.

*Arthur H. Medalie* *December 28, 2007*

(A) Diluted EPS. Next earnings report due late Jan. Excl. nonrecur. gain (losses): '00, 8¢; '01, (13¢); '03, (6¢); incl. charges for merger costs: '00, 60¢; '01, 17¢. (B) Div'ds historically paid in early March, early June, early September, and early December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. in '06, $5.27/sh. (D) In millions. (E) Electric rate base determination: fair value. Rate allowed on elect. common equity in '95: 12.25%. Earned on avg. com. eq. '06: 9.4%. Regulatory Climate: Above Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 75 |

# XCEL ENERGY NYSE-XEL

RECENT PRICE **20.60** | P/E RATIO **13.6** (Trailing: 15.4; Median: 15.0) | RELATIVE P/E RATIO **0.85** | DIV'D YLD **4.6%** | VALUE LINE

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 26.7 | 29.4 | 30.8 | 27.9 | 30.0 | 31.8 | 28.5 | 17.4 | 18.8 | 20.2 | 23.6 | 25.0 |
| Low: | 22.3 | 22.3 | 25.7 | 19.3 | 16.1 | 24.2 | 5.1 | 10.4 | 15.5 | 16.5 | 17.8 | 19.6 |

Target Price Range 2010 | 2011 | 2012

TIMELINESS **3** Lowered 3/16/07

SAFETY **2** Raised 5/14/04

TECHNICAL **2** Raised 1/11/08

BETA .80 (1.00 = Market)

**2010-12 PROJECTIONS**

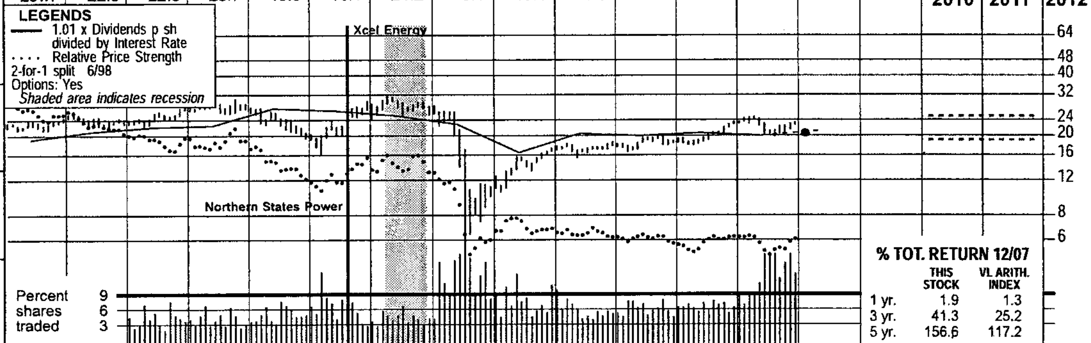
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 25 | (+20%) | 9% |
| Low | 19 | (-10%) | 3% |

**Insider Decisions**

| | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 170 | 175 | 160 |
| to Sell | 156 | 177 | 179 |
| Hld's(000) | 272870 | 275060 | 269962 |




**% TOT. RETURN 12/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 1.9 | 1.3 |
| 3 yr. | 41.3 | 25.2 |
| 5 yr. | 156.6 | 117.2 |

Xcel Energy was formed through the merger of Northern States Power and New Century Energies on August 21, 2000. NSP stockholders received one share of Xcel for every NSP share, and NCE stockholders received 1.55 shares of Xcel for each NCE share. Data prior to 2000 reflect NSP on a stand-alone basis and are not comparable with Xcel data.

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18.32 | 18.46 | 18.42 | 34.11 | 43.56 | 23.89 | 19.90 | 20.84 | 23.86 | 24.16 | 23.50 | 24.50 | Revenues per sh | 28.25 |
| 3.92 | 4.30 | 4.13 | 4.12 | 5.09 | 3.14 | 3.35 | 3.27 | 3.28 | 3.70 | 3.70 | 4.00 | "Cash Flow" per sh | 4.50 |
| 1.61 | 1.84 | 1.43 | 1.60 | 2.27 | .42 | 1.23 | 1.27 | 1.20 | 1.35 | 1.35 | 1.50 | Earnings per sh A | 1.75 |
| 1.40 | 1.43 | 1.45 | 1.48 | 1.50 | 1.13 | .75 | .81 | .85 | .88 | .91 | .95 | Div'd Decl'd per sh B ■ | 1.10 |
| 2.90 | 2.99 | 13.87 | 3.63 | 7.40 | 6.04 | 2.49 | 3.19 | 3.25 | 4.00 | 4.90 | 4.90 | Cap'l Spending per sh | 4.50 |
| 15.89 | 16.25 | 16.42 | 16.37 | 17.95 | 11.70 | 12.95 | 12.99 | 13.37 | 14.28 | 14.70 | 15.30 | Book Value per sh C | 17.00 |
| 149.24 | 152.70 | 155.73 | 339.79 | 345.02 | 398.71 | 398.96 | 400.46 | 403.39 | 407.30 | 427.00 | 429.00 | Common Shs Outst'g D | 435.00 |
| 15.5 | 15.2 | 16.6 | 14.3 | 12.4 | NMF | 11.6 | 13.6 | 15.4 | 14.8 | 16.7 | | Avg Ann'l P/E Ratio | 13.0 |
| .89 | .79 | .95 | .93 | .64 | NMF | .66 | .72 | .82 | .80 | .88 | | Relative P/E Ratio | .85 |
| 5.6% | 5.1% | 6.1% | 6.4% | 5.3% | 6.6% | 5.2% | 4.7% | 4.6% | 4.4% | 4.0% | | Avg Ann'l Div'd Yield | 4.8% |
| 2733.7 | 2819.2 | 2869.0 | 11592 | 15028 | 9524.4 | 7937.5 | 8345.3 | 9625.5 | 9840.3 | 10034 | 10500 | Revenues ($mill) | 12300 |
| 251.8 | 298.1 | 240.1 | 545.8 | 784.7 | 177.6 | 510.0 | 526.9 | 499.0 | 568.7 | 575.9 | 655 | Net Profit ($mill) | 750 |
| 27.8% | 26.0% | 21.6% | 35.8% | 28.2% | 32.7% | 23.7% | 23.2% | 25.8% | 24.2% | 33.8% | 33.5% | Income Tax Rate | 35.0% |
| 6.6% | 5.3% | 2.5% | 4.4% | 7.1% | 46.7% | 8.9% | 10.9% | 8.5% | 9.8% | 12.5% | 16.0% | AFUDC % to Net Profit | 9.0% |
| 40.4% | 39.9% | 54.7% | 58.8% | 66.7% | 59.6% | 55.3% | 55.0% | 51.7% | 52.1% | 51.5% | 54.0% | Long-Term Debt Ratio | 54.5% |
| 51.0% | 53.5% | 40.5% | 40.5% | 32.8% | 39.5% | 43.8% | 44.1% | 47.3% | 47.0% | 47.5% | 45.0% | Common Equity Ratio | 45.0% |
| 4650.9 | 4637.7 | 6316.2 | 13745 | 18911 | 11815 | 11790 | 11801 | 11398 | 12371 | 13150 | 14525 | Total Capital ($mill) | 16500 |
| 4361.3 | 4395.2 | 4451.5 | 15273 | 21165 | 18816 | 13667 | 14096 | 14696 | 15549 | 16675 | 17750 | Net Plant ($mill) | 19700 |
| 6.9% | 8.1% | 5.4% | 6.0% | 6.0% | 5.4% | 6.1% | 6.2% | 6.2% | 6.2% | 6.0% | 6.0% | Return on Total Cap'l | 6.5% |
| 9.1% | 10.7% | 8.4% | 9.6% | 12.5% | 3.7% | 9.7% | 9.9% | 9.1% | 9.6% | 9.0% | 10.0% | Return on Shr. Equity | 10.0% |
| 9.5% | 11.2% | 8.6% | 9.7% | 12.6% | 3.7% | 9.8% | 10.0% | 9.2% | 9.7% | 9.0% | 10.0% | Return on Com Equity E | 10.0% |
| 1.2% | 2.5% | NMF | .9% | 4.3% | NMF | 3.9% | 3.9% | 2.9% | 3.6% | 3.0% | 3.5% | Retained to Com Eq | 3.5% |
| 88% | 79% | 100% | 91% | 66% | NMF | 60% | 62% | 69% | 63% | 67% | 63% | All Div'ds to Net Prof | 64% |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $7980.0 mill. **Due in 5 Yrs** $2751.0 mill.
**LT Debt** $7252.8 mill. **LT Interest** $471.0 mill.
Incl. 8,000,000 shares 7.875% tax-deductible Trust Originated Preferred Securities, liquidation value $25/share; 7,760,000 shares 7.60%, cumulative, $25 par; $100 mill. 7.85% tax-deductible Trust Preferred Securities.
(LT interest earned: 2.5x)
**Leases, Uncapitalized** Annual rentals $57.4 mill.
**Pension Assets-12/06** $3.18 bill. **Oblig.** $2.67 bill.
**Pfd Stock** $105.0 mill. **Pfd Div'd** $4.2 mill.
1,049,800 shares $3.60 to $4.56, cumulative, $100 par, callable $102.00 to $103.75.
**Common Stock** 419,930,078 shs. **as of 10/19/07**
**MARKET CAP: $8.7 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +.3 | +3.6 | +1.8 |
| Avg. C & I Use (MWH) | 145 | 150 | 153 |
| Avg. C & I Revs. per KWH (¢) | 5.51 | 6.22 | 6.55 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 19827 | 20854 | 21255 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.0 | -.4 | +1.2 |
| Fixed Charge Cov. (%) | 230 | 232 | 238 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 2.0% | -6.5% | 3.5% |
| "Cash Flow" | -2.0% | -5.5% | 4.5% |
| Earnings | -3.5% | -6.5% | 5.5% |
| Dividends | -4.5% | -10.5% | 4.5% |
| Book Value | -1.0% | -4.5% | 4.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 2280 | 1797 | 2009 | 2259 | 8345.3 |
| 2005 | 2381 | 2074 | 2289 | 2882 | 9625.5 |
| 2006 | 2888 | 2074 | 2412 | 2466 | 9840.3 |
| 2007 | 2764 | 2267 | 2400 | 2603 | 10034 |
| 2008 | 2850 | 2350 | 2600 | 2700 | 10500 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .36 | .21 | .40 | .31 | 1.27 |
| 2005 | .31 | .18 | .47 | .24 | 1.20 |
| 2006 | .36 | .24 | .53 | .23 | 1.35 |
| 2007 | .28F | .16F | .59F | .31 | 1.35 |
| 2008 | .32 | .30 | .58 | .30 | 1.50 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .188 | .188 | .208 | .208 | .79 |
| 2005 | .208 | .208 | .215 | .215 | .85 |
| 2006 | .215 | .215 | .223 | .223 | .88 |
| 2007 | .223 | .223 | .23 | .23 | .91 |
| 2008 | | | | | |

**BUSINESS:** Xcel Energy Inc. is the parent of Northern States Power, which supplies power to Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, & gas to Minnesota, Wisconsin, North Dakota, & Michigan; Public Service of Colorado, which supplies power & gas to Colorado; & Southwestern Public Service, which supplies power to Texas & New Mexico. Customers: 3.3 mill. electric, 1.8 mill. gas. Electric revenue breakdown, '06: residential, 28%; commercial & industrial, 53%; other, 19%. Generating sources not available. Fuel costs: 58% of revs. '06 reported deprec. rate: 3.2%. Has 9,700 employees. Chairman, President & CEO: Richard C. Kelly. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

**Xcel Energy has received a rate order in Wisconsin.** The electric and gas tariffs of Northern States Power (NSP) were raised by $39.4 million (8.1%) and $5.3 million (3.3%), based on a return of 10.75% on a common-equity ratio of 52.5%. New rates went into effect on January 9th.

**Several other regulatory matters are pending or upcoming.** In North Dakota, NSP filed for an electric rate hike of $20.5 million (14%) based on a return of 11.5% on a common-equity ratio of 51.77%. An interim rate increase of $17.2 million took effect on February 5th, and a final order is expected this fall. The utility and the commission's staff have agreed on an allowed ROE of 10.75%, subject to commission approval. In New Mexico, Southwestern Public Service (SPS) is seeking a $17.3 million (6.6%) electric tariff increase, based on a return of 11% on a common-equity ratio of 51.2%. An order is due this summer. The company intends to file electric rate cases in Texas this spring, and in Colorado and Minnesota this fall.

**We expect higher earnings in 2008.** Rate relief and an increase in the Allowance for Funds Used During Construction, a noncash credit to income, should be the key factors. Our estimate is at the midpoint of Xcel's targeted range of $1.45-$1.55 a share.

**Frequent rate cases are necessary for Xcel to place its capital spending into the rate base and to recover ongoing increases in operating expenses.** The company has had major capital projects in Minnesota and Colorado. The utility is earning or nearly earning its allowed return on equity in most of its jurisdictions, but the returns of SPS in Texas and New Mexico are still a sore spot.

**This stock offers a yield that is fractionally above the average for the electric utility industry.** Total-return potential to 2010-2012 is only about average for a utility, however.

**The SEC ordered Xcel to reclassify the cost of a settlement with the IRS concerning the deductibility of company-owned life insurance.** Xcel was treating this charge as a discontinued item, but had to shift it to ongoing results. This lowered 2007 share net by $0.08. We are *including* this in our presentation.

*Paul E. Debbas, CFA* *February 8, 2008*

(A) Diluted EPS. Excl. nonrec. loss: '02, $6.27; gains (losses) on disc. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢. '04, '06, & '07 EPS don't add due to rounding. Next egs. report due late Apr. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '06: $4.36/sh. (D) In mill., adj. for split. (E) Rate base: Varies. Rate all'd on com. eq.: MN '93, 11.47%; WI '08, 10.75%; CO '03 (elec.), 10.75%; CO '07 (gas) 10.25%; TX '86, 15.05%; earned on avg. com. eq., '06: 10.1%. Regulatory Climate: Avg. (F) Restated.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 5 |
| Earnings Predictability | 45 |

# UNISOURCE ENERGY NYSE-UNS

RECENT PRICE 29.41 | P/E RATIO 17.0 (Trailing: 20.4 / Median: 16.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 3.3% | VALUE LINE

**TIMELINESS** 4 Raised 8/17/07

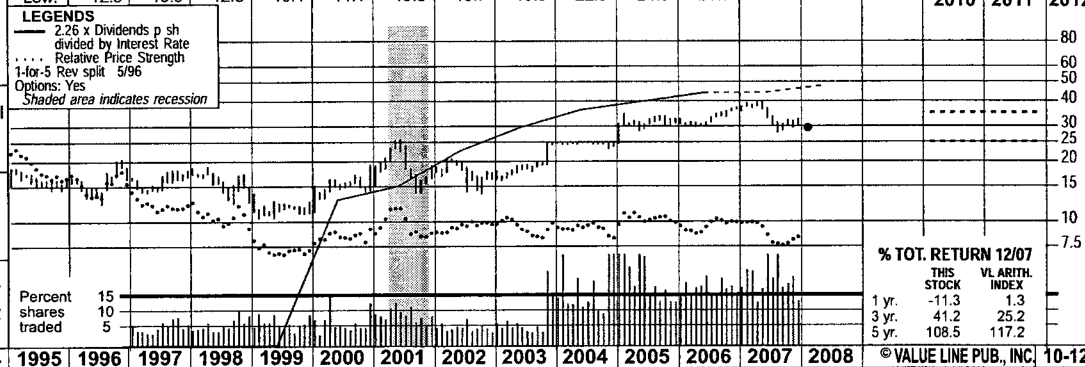
**SAFETY** 3 New 12/31/04

**TECHNICAL** 2 Raised 2/1/08

**BETA** .60 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 20.8 | 18.3 | 18.9 | 13.9 | 19.3 | 26.0 | 20.8 | 24.9 | 24.9 | 34.8 | 37.5 | 40.0 |
| Low: | 12.3 | 13.9 | 12.3 | 10.4 | 11.1 | 13.8 | 13.7 | 16.0 | 22.9 | 24.3 | 29.5 | 27.6 |

**LEGENDS**
— 2.26 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-5 Rev split 5/96
Options: Yes
*Shaded area indicates recession*



Target Price Range 2010 | 2011 | 2012

### 2010-12 PROJECTIONS

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 35 | (+20%) | *8%* |
| Low | 25 | (-15%) | *Nil* |

### Insider Decisions

| | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 1 | 0 | 4 | 0 | 0 | 1 | 0 | 0 | 2 |
| to Sell | 1 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 1 |

### Institutional Decisions

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 87 | 73 | 56 |
| to Sell | 67 | 81 | 87 |
| Hld's(000) | 31380 | 30634 | 31880 |

Percent shares traded 15 10 5

**% TOT. RETURN 12/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -11.3 | 1.3 |
| 3 yr. | 41.2 | 25.2 |
| 5 yr. | 108.5 | 117.2 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 114.58 | 19.56 | 20.61 | 21.51 | 20.87 | 22.28 | 22.71 | 23.83 | 24.85 | 31.12 | 43.12 | 25.50 | 28.71 | 34.13 | 35.26 | 37.42 | *38.65* | *40.60* | Revenues per sh | *45.60* |
| d12.43 | d.30 | 2.06 | 3.44 | 4.58 | 6.82 | 5.29 | 3.48 | 3.96 | 4.23 | 5.41 | 4.80 | 5.20 | 5.29 | 5.21 | 5.68 | *5.40* | *5.70* | "Cash Flow" per sh | *6.35* |
| d28.05 | d12.40 | d.25 | .65 | 1.70 | 3.76 | 2.60 | .68 | 1.08 | 1.27 | 1.79 | .97 | 1.30 | 1.31 | 1.30 | 1.85 | *1.60* | *1.75* | Earnings per sh A | *1.90* |
| -- | -- | -- | -- | -- | -- | -- | -- | -- | .32 | .40 | .50 | .60 | .64 | .76 | .84 | .90 | *.96* | Div'd Decl'd per sh B ■ † | *1.14* |
| 8.75 | 1.08 | 1.50 | 1.95 | 1.84 | 2.07 | 2.22 | 2.52 | 2.87 | 3.19 | 3.63 | 3.36 | 4.06 | 4.49 | 5.83 | 6.77 | *5.55* | *6.50* | Cap'l Spending per sh | *7.75* |
| d37.31 | d1.19 | d1.96 | d1.31 | .39 | 4.15 | 6.75 | 7.65 | 10.02 | 11.20 | 12.68 | 13.05 | 15.97 | 16.95 | 17.68 | 18.59 | *19.55* | *20.85* | Book Value per sh C | *22.25* |
| 5.14 | 32.09 | 32.14 | 32.14 | 32.13 | 32.13 | 32.14 | 32.26 | 32.35 | 33.22 | 33.50 | 33.58 | 33.79 | 34.26 | 34.87 | 35.19 | *35.70* | *36.20* | Common Shs Outst'g D | *37.70* |
| -- | -- | -- | 26.7 | 9.6 | 4.3 | 6.1 | 23.3 | 10.8 | 11.8 | 10.8 | 18.2 | 14.6 | 18.7 | 23.9 | 17.7 | *18.4* | | Avg Ann'l P/E Ratio | *16.0* |
| -- | -- | -- | 1.75 | .64 | .27 | .35 | 1.21 | .62 | .77 | .55 | .99 | .83 | .99 | 1.27 | .96 | *.97* | | Relative P/E Ratio | *1.05* |
| -- | -- | -- | -- | -- | -- | -- | -- | -- | 2.1% | 2.1% | 2.8% | 3.2% | 2.6% | 2.5% | 2.6% | 3.1% | | Avg Ann'l Div'd Yield | *3.8%* |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $1607.2 mill. **Due in 5 Yrs** $1079.6 mill.
**LT Debt** $1532.3 mill. **LT Interest** $145.6 mill.
Incl. $528.9 mill. capitalized leases.

(LT interest earned: 1.6x)

**Pension Assets-12/06** $176 mill. **Oblig.** $218 mill.
**Pfd Stock** None

**Common Stock** 35,338,420 shs. **as of 10/31/07**
**MARKET CAP: $1.1 billion (Mid Cap)**

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 729.9 | 768.7 | 803.8 | 1033.7 | 1444.7 | 856.2 | 969.9 | 1169.0 | 1229.5 | 1316.9 | *1380* | *1470* | Revenues ($mill) | *1720* |
| 83.6 | 21.9 | 35.5 | 26.3 | 60.9 | 33.3 | 45.2 | 45.9 | 46.1 | 69.2 | *57.0* | *63.0* | Net Profit ($mill) | *71.0* |
| -- | 45.6% | 46.8% | 32.9% | 43.8% | 33.7% | 19.7% | 42.5% | 41.4% | 38.8% | *39.0%* | *39.0%* | Income Tax Rate | *39.0%* |
| -- | -- | -- | -- | -- | -- | 2.2% | -- | 2.2% | 2.9% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| 90.7% | 89.4% | 86.1% | 84.2% | 79.6% | 81.5% | 79.2% | 77.1% | 75.3% | 72.9% | *68.5%* | *67.0%* | Long-Term Debt Ratio | *61.0%* |
| 9.3% | 10.6% | 13.9% | 15.8% | 20.4% | 18.5% | 20.8% | 22.9% | 24.7% | 27.1% | *31.5%* | *33.0%* | Common Equity Ratio | *39.0%* |
| 2322.3 | 2320.6 | 2340.5 | 2362.4 | 2081.3 | 2368.8 | 2589.0 | 2540.3 | 2494.9 | 2414.1 | *2230* | *2245* | Total Capital ($mill) | *2290* |
| 1935.5 | 1915.6 | 1729.9 | 1706.3 | 1677.7 | 1668.4 | 2069.2 | 2081.1 | 2171.5 | 2259.6 | *2320* | *2415* | Net Plant ($mill) | *2545* |
| 5.0% | 2.5% | 2.9% | 2.5% | 4.4% | 2.8% | 4.9% | 5.1% | 5.1% | 5.9% | *5.5%* | *5.5%* | Return on Total Cap'l | *6.0%* |
| 38.5% | 8.9% | 11.0% | 7.1% | 14.3% | 7.6% | 8.4% | 7.9% | 7.5% | 10.6% | *8.0%* | *8.5%* | Return on Shr. Equity | *8.5%* |
| 38.5% | 8.9% | 11.0% | 7.1% | 14.3% | 7.6% | 8.4% | 7.9% | 7.5% | 10.6% | *8.0%* | *8.5%* | Return on Com Equity E | *8.5%* |
| 38.5% | 8.9% | 11.0% | 4.3% | 11.2% | 3.8% | 4.6% | 4.1% | 3.2% | 6.1% | *3.5%* | *3.5%* | Retained to Com Eq | *3.5%* |
| -- | -- | -- | 39% | 22% | 51% | 45% | 48% | 57% | 43% | *56%* | *55%* | All Div'ds to Net Prof | *60%* |

### ELECTRIC OPERATING STATISTICS

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.2 | +3.9 | +3.7 |
| Avg. Indust. Use (MWH) | 3293 | 3421 | 3431 |
| Avg. Indust. Revs. per KWH (¢) | 6.50 | 6.60 | 6.60 |
| Capacity at Peak (Mw) | 2275 | 2567 | 2696 |
| Peak Load, Summer (Mw) | 2458 | 2792 | 2913 |
| Annual Load Factor (%) | 64.6 | 63.9 | 64.0 |
| % Change Customers (yr-end) | +2.1 | +2.6 | +1.8 |
| Fixed Charge Cov. (%) | 130 | 131 | 157 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 5.0% | 1.5% | *4.0%* |
| "Cash Flow" | 1.0% | 3.5% | *3.0%* |
| Earnings | -3.0% | 1.5% | *4.0%* |
| Dividends | -- | NMF | *7.0%* |
| Book Value | 32.5% | 9.5% | *4.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 270.1 | 290.1 | 335.3 | 273.5 | 1169.0 |
| 2005 | 260.9 | 300.6 | 349.3 | 318.7 | 1229.5 |
| 2006 | 305.0 | 318.4 | 375.6 | 317.9 | 1316.9 |
| 2007 | 317.8 | 329.8 | 398.2 | *334.2* | *1380* |
| 2008 | *345* | *360* | *415* | *350* | *1470* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .18 | .37 | .68 | .08 | 1.31 |
| 2005 | d.11 | .27 | .49 | .65 | 1.30 |
| 2006 | .52 | .28 | .73 | .32 | 1.85 |
| 2007 | .14 | .33 | .66 | *.47* | *1.60* |
| 2008 | *.25* | *.35* | *.75* | *.40* | *1.75* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .16 | .16 | .16 | .16 | .64 |
| 2005 | .19 | .19 | .19 | .19 | .76 |
| 2006 | .21 | .21 | .21 | .21 | .84 |
| 2007 | .225 | .225 | .225 | .225 | .90 |
| 2008 | | | | | |

**BUSINESS:** UniSource Energy Corp., parent of Tucson Electric Power Company, supplies electricity in Tucson, Arizona and the surround. area (serv. area: 1,155 sq. miles). Nonutility subsidiaries engage in plant construction, fuel supply, and related businesses. Revenue sources: residential, 44%; commercial, 26%; industrial, 21%; other, 9%. Copper mining is largest industry served. Fuels: coal, 81%; gas, 6%; purchased power, 13%. Fuel: 46% of electric revenues; labor costs: 9%. '06 depreciation rate: 3.1%. Estimated plant age: 10 years. Has 1,260 employees. Chairman, President, and CEO: James S. Pignatelli. Inc.: AZ. Address: One South Church Ave. Suite 1820, Tucson, AZ 85701. Tel.: 520-884-3650. Internet: www.unisourceenergy.com.

**UniSource seeks higher rates.** A 1999 agreement froze electric rates through the end of 2008. As required by regulators, UNS filed for new rates that would take effect in January, 2009. It recommended that the commission use one of three methods in setting new tariffs. In all three cases, transmission and distribution rates are based on historic cost-based calculations. But rates for generated power are figured differently under each approach. In the first instance, charges would be based on wholesale market prices. An alternative ties rates to historic costs, subject to a separate charge. Either procedure would raise annual rates by about 22%. A third option blends the first two and results in lesser rates. All proposals reward customers for energy conservation. An order on the application will take effect January 1, 2009.

**Financial indicators will remain weak for a while.** Though long-term debt has been reduced steadily since 1996, it still accounts for about 70% of total capital. What's more, meaningful reductions are unlikely for a while because of the need to finance the capital spending program. That, in turn, keeps pressure on fixed charges, which have been barely earned since 1997. Too, though a large percentage of profits are being plowed back into retained earnings, this account still had a negative balance last September, 30th. Finally, UNS is having difficulty earning its allowed return on equity. In view of these negatives, we rate the company's Financial Strength a below-average C++.

**Earnings should improve in 2008.** Planned and unplanned plant outages, which took a toll in last year's first quarter, are behind the company. UNS should also benefit from an order on a filing for $9 million in higher posted gas tariffs. In all, we think 2008 earnings will rise 9% over last year's estimated $1.60 a share. An order on the aforementioned electric rate filing suggests a further gain next year. The stock is untimely.

**These shares offer an even balance of pluses and minuses.** Above-average dividend growth prospects to 2010-2012 might interest income-oriented investors. But those of a conservative bent may hesitate because of the company's weak finances.

*Arthur H. Medalie* *February 8, 2008*

(A) EPS diluted. Next earnings report due late Feb. Excl. nonrecur. gains (losses): '91, ($12.49); '92, 18¢; '93, ($0.11); '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00.
(B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '06: $6.38/sh. (D) In millions, adjusted for split. (E) Rate base: fair value. Rate allowed on com. eq. in '94: 11.0%; earned on avg. com. eq., '06: 10.3%. Regulatory Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | C++ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 90 |
| Earnings Predictability | 40 |

# ATTACHMENT B

**Zacks.com Quotes and Research**

| **ALLETE INC.** (NYSE) | | | | Scottrade | |
|---|---|---|---|---|---|
| ALE | 37.05 | ▼-0.35 | (-0.94%) | Vol. 46,300 | 11:54 ET |

ALLETE is a multi-services company. ALLETE's holdings include the one of the largest wholesale automobile auction networks in North America; a provider of independent auto dealer inventory financing; one of the largest investor-owned water utilities in Florida and North Carolina; significant real estate holdings in Florida and a low-cost electric utility that serves some of the largest industrial customers in the United States. (Company Press Release)

## General Information

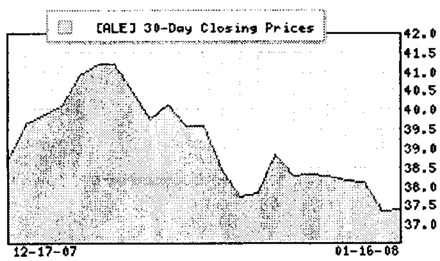
ALLETE INC
30 West Superior Street
Duluth, MN 55802-2093
Phone: 218 279-5000
Fax: -
Web: www.allete.com
Email: tthorp@allete.com

| | |
|---|---|
| Industry | DIVERSIFIED OPS |
| Sector: | Multi-Sector Conglomerates |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/15/2008 |

## Price and Volume Information

| | |
|---|---|
| Zacks Rank | 2 |
| Yesterday's Close | 37.40 |
| 52 Week High | 51.30 |
| 52 Week Low | 37.04 |
| Beta | 1.17 |
| 20 Day Moving Average | 193,200.91 |
| Target Price Consensus | 52.67 |




**% Price Change**

| | |
|---|---|
| 4 Week | -6.27 |
| 12 Week | -15.99 |
| YTD | -5.51 |

**% Price Change Relative to S&P 500**

| | |
|---|---|
| 4 Week | -0.82 |
| 12 Week | -7.26 |
| YTD | 1.02 |

**Share Information**

| | |
|---|---|
| Shares Outstanding (millions) | 30.82 |
| Market Capitalization (millions) | 1,152.74 |
| Short Ratio | 15.00 |
| Last Split Date | 09/21/2004 |

**Dividend Information**

| | |
|---|---|
| Dividend Yield | 4.39% |
| Annual Dividend | $1.64 |
| Payout Ratio | 0.00 |
| Change in Payout Ratio | 0.00 |
| Last Dividend Payout / Amount | 11/13/2007 / $0.41 |

## EPS Information

| | |
|---|---|
| Current Quarter EPS Consensus Estimate | 0.69 |
| Current Year EPS Consensus Estimate | 3.00 |
| Estimated Long-Term EPS Growth Rate | 5.00 |
| Next EPS Report Date | 02/15/2008 |

## Consensus Recommendations

| | |
|---|---|
| Current (1=Strong Buy, 5=Strong Sell) | 1.60 |
| 30 Days Ago | 1.60 |
| 60 Days Ago | 1.60 |
| 90 Days Ago | 1.00 |

## Fundamental Ratios

| **P/E** | | **EPS Growth** | | **Sales Growth** | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.33 | vs. Previous Year | -26.58% | vs. Previous Year | 0.85% |
| Trailing 12 Months: | 11.95 | vs. Previous Quarter | -27.50% | vs. Previous Quarter: | -10.08% |
| PEG Ratio | 2.67 | | | | |

**Price Ratios** **ROE** **ROA**

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.58 | 09/30/07 | - | 09/30/07 | - |
| Price/Cash Flow | 9.02 | 06/30/07 | 12.67 | 06/30/07 | 5.55 |
| Price / Sales | - | 03/31/07 | 13.83 | 03/31/07 | 6.13 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 2.06 | 06/30/07 | 1.69 | 06/30/07 | 10.69 |
| 03/31/07 | 2.35 | 03/31/07 | 1.99 | 03/31/07 | 11.37 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 16.66 | 06/30/07 | 16.66 | 06/30/07 | 23.60 |
| 03/31/07 | 17.81 | 03/31/07 | 17.81 | 03/31/07 | 23.37 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 7.25 | 06/30/07 | 0.56 | 06/30/07 | 36.59 |
| 03/31/07 | 7.20 | 03/31/07 | 0.57 | 03/31/07 | 36.95 |

**ZACKS** INVESTMENT RESEARCH
*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## ALLIANT ENERGY CP (NYSE)

Scottrade

| LNT | 36.88 | -0.02 | (-0.05%) | Vol. 276,425 | 12:25 ET |
|---|---|---|---|---|---|

Alliant Energy Corp. is a growing energy-services provider with operations both domestically and internationally. Alliant Energy provides electric, natural gas, water and steam services to customers worldwide. Alliant Energy Resources, Inc., the home of the company's non-regulated businesses, has operations and investments throughout the United States as well as in Australia, Brazil, China, Mexico and New Zealand. (Company Press Release)

### General Information

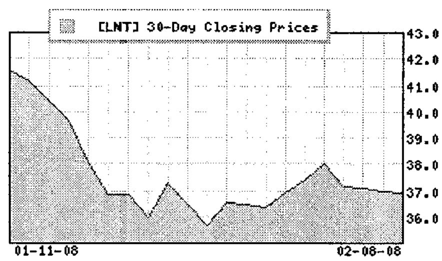
ALLIANT ENGY CP
4902 N. Biltmore Lane
Madison, WI 53718
Phone: 608 458-3311
Fax: 608-259-7269
Web: www.alliantenergy.com
Email: shareownerservices@alliantenergy.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 05/09/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 36.90 |
| 52 Week High | 46.53 |
| 52 Week Low | 34.95 |
| Beta | 0.83 |
| 20 Day Moving Average | 729,997.63 |
| Target Price Consensus | 42.56 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -11.30 | 4 Week | -6.65 |
| 12 Week | -10.13 | 12 Week | -1.53 |
| YTD | -9.31 | YTD | 0.02 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 110.32 | Dividend Yield | 3.79% |
| | | Annual Dividend | $1.40 |
| Market Capitalization (millions) | 4,070.66 | Payout Ratio | 0.50 |
| Short Ratio | 3.09 | Change in Payout Ratio | -0.04 |
| Last Split Date | N/A | Last Dividend Payout / Amount | 01/29/2008 / $0.35 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.65 | Current (1=Strong Buy, 5=Strong Sell) | 2.33 |
| Current Year EPS Consensus Estimate | 2.68 | 30 Days Ago | 2.33 |
| Estimated Long-Term EPS Growth Rate | 6.00 | 60 Days Ago | 2.33 |
| Next EPS Report Date | 05/09/2008 | 90 Days Ago | 2.00 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.77 | vs. Previous Year | -3.51% | vs. Previous Year | 3.84% |
| Trailing 12 Months: | 14.41 | vs. Previous Quarter | -47.62% | vs. Previous Quarter: | -3.71% |
| PEG Ratio | 2.29 | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 1.64 | 12/31/07 | 11.37 | 12/31/07 | 4.22 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 8.68 | 09/30/07 | 11.45 | 09/30/07 | 4.26 |
| Price / Sales | 1.18 | 06/30/07 | 10.37 | 06/30/07 | 3.84 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 8.34 |
| 09/30/07 | 1.13 | 09/30/07 | 0.84 | 09/30/07 | 8.59 |
| 06/30/07 | 0.81 | 06/30/07 | 0.61 | 06/30/07 | 7.79 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 20.28 | 09/30/07 | 20.28 | 09/30/07 | 22.44 |
| 06/30/07 | 19.09 | 06/30/07 | 19.09 | 06/30/07 | 21.95 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 8.50 | 09/30/07 | 0.63 | 09/30/07 | 36.71 |
| 06/30/07 | 10.44 | 06/30/07 | 0.52 | 06/30/07 | 32.19 |

ZACKS
PROFIT FROM THE PROS

**Zacks.com Quotes and Research**

## AMEREN CP (NYSE)

Scottrade

| | | | | | |
|---|---|---|---|---|---|
| AEE | 49.06 | -1.50 | (-2.97%) | Vol. 1,331,490 | 12:10 ET |

Ameren Corporation companies provide energy services customers in Missouri and Illinois. AmerenUE, one of its subsidiaries, is the one of the largest electric utilities in Missouri and distributors of natural gas. AmerenCIPS, another subsidiary, is both an electric and natural gas utility and serves one of the largest geographic areas of Illinois-based utility companies. (Company Press Release)

### General Information

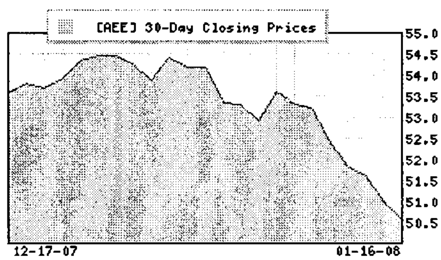
AMEREN CORP
1901 Chouteau Avenue
St. Louis, MO 63103
Phone: 314 621-3222
Fax: 314 621-2888
Web: www.ameren.com
Email: invest@ameren.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/14/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 50.56 |
| 52 Week High | 55.00 |
| 52 Week Low | 47.10 |
| Beta | 0.68 |
| 20 Day Moving Average | 1,027,967.31 |
| Target Price Consensus | 54 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -5.83 | 4 Week | -0.36 |
| 12 Week | -3.71 | 12 Week | 6.29 |
| YTD | -6.73 | YTD | 0.26 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 208.01 | Dividend Yield | 5.02% |
| | | Annual Dividend | $2.54 |
| Market Capitalization (millions) | 10,516.94 | Payout Ratio | 0.00 |
| Short Ratio | 4.36 | Change in Payout Ratio | 0.00 |
| Last Split Date | N/A | Last Dividend Payout / Amount | 12/03/2007 / $0.63 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.55 | Current (1=Strong Buy, 5=Strong Sell) | 3.00 |
| Current Year EPS Consensus Estimate | 3.29 | 30 Days Ago | 3.00 |
| Estimated Long-Term EPS Growth Rate | 6.20 | 60 Days Ago | 3.00 |
| Next EPS Report Date | 02/14/2008 | 90 Days Ago | 3.00 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.17 | vs. Previous Year | -4.23% | vs. Previous Year | 4.55% |
| Trailing 12 Months: | 16.47 | vs. Previous Quarter | 97.10% | vs. Previous Quarter: | 15.90% |
| PEG Ratio | 2.29 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.55 | 09/30/07 | - | 09/30/07 | - |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 7.98 | 06/30/07 | 9.60 | 06/30/07 | 3.18 |
| Price / Sales | - | 03/31/07 | 9.85 | 03/31/07 | 3.30 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 0.93 | 06/30/07 | 0.63 | 06/30/07 | 8.65 |
| 03/31/07 | 0.91 | 03/31/07 | 0.69 | 03/31/07 | 8.91 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 12.18 | 06/30/07 | 12.18 | 06/30/07 | 32.54 |
| 03/31/07 | 13.48 | 03/31/07 | 13.48 | 03/31/07 | 31.97 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 5.39 | 06/30/07 | 0.81 | 06/30/07 | 45.83 |
| 03/31/07 | 5.31 | 03/31/07 | 0.83 | 03/31/07 | 45.52 |

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## AMER ELECTRIC POW CO (NYSE)

Scottrade

| AEP | 43.40 | ▲0.24 | (0.56%) | Vol. 1,978,800 | 12:30 ET |
|---|---|---|---|---|---|

American Electric Power is a public utility holding company which owns,directly or indirectly, all of the outstanding common stock of its domesticelectric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. The Company's operations are divided into three business segments: Wholesale, Energy Delivery and Other.

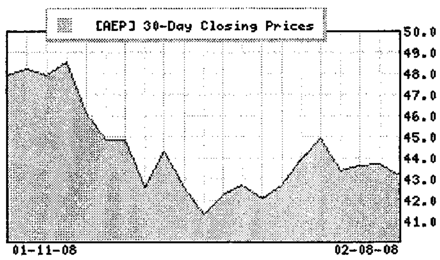
### General Information

AMER ELEC PWR
1 Riverside Plaza
Columbus, OH 43215
Phone: 614 716-1000
Fax: 614 223-1823
Web: www.aep.com
Email: jsloat@aep.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 04/24/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 43.16 |
| 52 Week High | 51.24 |
| 52 Week Low | 40.68 |
| Beta | 0.88 |
| 20 Day Moving Average | 3,815,779.25 |
| Target Price Consensus | 49.6 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -10.01 | 4 Week | -5.29 |
| 12 Week | -7.00 | 12 Week | 1.90 |
| YTD | -7.30 | YTD | 2.24 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 400.01 | Dividend Yield | 3.80% |
| | | Annual Dividend | $1.64 |
| Market Capitalization (millions) | 17,264.26 | Payout Ratio | 0.55 |
| Short Ratio | 1.24 | Change in Payout Ratio | -0.02 |
| Last Split Date | N/A | Last Dividend Payout / Amount | 02/06/2008 / $0.41 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.72 | Current (1=Strong Buy, 5=Strong Sell) | 2.45 |
| Current Year EPS Consensus Estimate | 3.18 | 30 Days Ago | 2.42 |
| Estimated Long-Term EPS Growth Rate | 5.40 | 60 Days Ago | 2.42 |
| Next EPS Report Date | 04/24/2008 | 90 Days Ago | 2.42 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.56 | vs. Previous Year | 36.84% | vs. Previous Year | 10.00% |
| Trailing 12 Months: | 14.39 | vs. Previous Quarter | -55.17% | vs. Previous Quarter: | -13.16% |
| PEG Ratio | 2.51 | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 1.74 | 12/31/07 | 12.36 | 12/31/07 | 3.09 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 6.67 | 09/30/07 | 11.85 | 09/30/07 | 2.95 |
| Price / Sales | 1.29 | 06/30/07 | 11.23 | 06/30/07 | 2.83 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 8.95 |
| 09/30/07 | 0.53 | 09/30/07 | 0.33 | 09/30/07 | 8.71 |
| 06/30/07 | 0.56 | 06/30/07 | 0.38 | 06/30/07 | 8.30 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 12.53 | 09/30/07 | 12.53 | 09/30/07 | 24.82 |
| 06/30/07 | 11.06 | 06/30/07 | 11.06 | 06/30/07 | 24.22 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 6.01 | 09/30/07 | 1.40 | 09/30/07 | 58.17 |
| 06/30/07 | 7.15 | 06/30/07 | 1.35 | 06/30/07 | 57.51 |

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## CH ENERGY GRP HLDG (NYSE)

| | | | | | | |
|---|---|---|---|---|---|---|
| CHG | 38.09 | ▾-0.93 | (-2.38%) | Vol. 32,800 | Scottrade | 12:15 ET |

CENTRAL HUDSON GAS & ELECTRIC generates, purchases and distributes electricity and purchases and distributes gas. The Company, in the opinion of its general counsel, has, with minor exceptions, valid franchises, unlimited in duration, to serve a territory extending about 85 miles along the Hudson River and about 25 to 40 miles east and west from such River. The southern end of the territory is about 25 miles north of New York City, and the northern end is about 10 miles south of the City of Albany.

### General Information

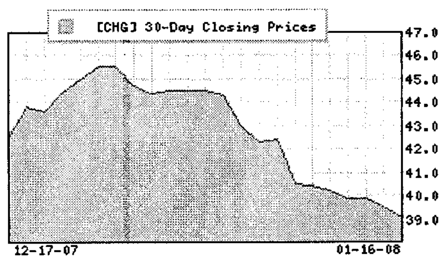
CH ENERGY GRP
284 South Avenue
Poughkeepsie, NY 12601-4879
Phone: 845 452-2000
Fax: 914 486-5415
Web: www.chenergygroup.com
Email: customerservices@cenhud.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/12/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 39.02 |
| 52 Week High | 53.00 |
| 52 Week Low | 38.87 |
| Beta | 0.77 |
| 20 Day Moving Average | 94,920.00 |
| Target Price Consensus | N/A |




**% Price Change**

| | |
|---|---|
| 4 Week | -10.57 |
| 12 Week | -15.12 |
| YTD | -12.39 |

**% Price Change Relative to S&P 500**

| | |
|---|---|
| 4 Week | -5.37 |
| 12 Week | -6.30 |
| YTD | -6.18 |

**Share Information**

| | |
|---|---|
| Shares Outstanding (millions) | 15.76 |
| Market Capitalization (millions) | 615.03 |
| Short Ratio | 16.83 |
| Last Split Date | N/A |

**Dividend Information**

| | |
|---|---|
| Dividend Yield | 5.54% |
| Annual Dividend | $2.16 |
| Payout Ratio | 0.00 |
| Change in Payout Ratio | 0.00 |
| Last Dividend Payout / Amount | 01/08/2008 / $0.54 |

### EPS Information

| | |
|---|---|
| Current Quarter EPS Consensus Estimate | N/A |
| Current Year EPS Consensus Estimate | 2.60 |
| Estimated Long-Term EPS Growth Rate | - |
| Next EPS Report Date | 02/12/2008 |

### Consensus Recommendations

| | |
|---|---|
| Current (1=Strong Buy, 5=Strong Sell) | 3.00 |
| 30 Days Ago | 3.00 |
| 60 Days Ago | 0.00 |
| 90 Days Ago | 0.00 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | - | vs. Previous Year | -61.43% | vs. Previous Year | 8.46% |
| Trailing 12 Months: | 15.07 | vs. Previous Quarter | -18.18% | vs. Previous Quarter: | -4.01% |
| PEG Ratio | - | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.16 | 09/30/07 | - | 09/30/07 | - |
| Price/Cash Flow | 7.80 | 06/30/07 | 7.84 | 06/30/07 | 2.77 |
| Price / Sales | - | 03/31/07 | 9.18 | 03/31/07 | 3.30 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 1.75 | 06/30/07 | 1.51 | 06/30/07 | 3.74 |
| 03/31/07 | 1.64 | 03/31/07 | 1.45 | 03/31/07 | 4.42 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 5.70 | 06/30/07 | 5.70 | 06/30/07 | 33.51 |
| 03/31/07 | 6.65 | 03/31/07 | 6.65 | 03/31/07 | 33.22 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 26.17 | 06/30/07 | 0.76 | 06/30/07 | 42.47 |
| 03/31/07 | 26.75 | 03/31/07 | 0.71 | 03/31/07 | 41.55 |

**Zacks.com Quotes and Research**

## CENTRAL VT PUB SVC (NYSE)

| CV | 28.76 | -0.41 | (-1.41%) | Vol. 36,900 | 12:21 ET |
|---|---|---|---|---|---|

Central Vermont Public Service Corporation is engaged in the purchase, production, transmission, distribution and sale of electricity.

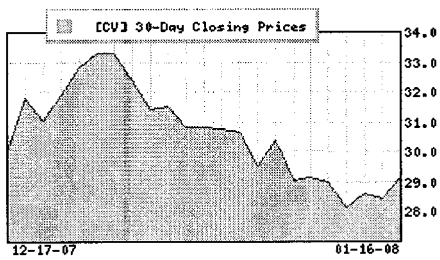
### General Information

CENTRAL VT PS
77 Grove Street
Rutland, VT 05701
Phone: 802 773-2711
Fax: 802 773-1775
Web: www.cvps.com
Email: eryan@cvps.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | N/A |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 29.17 |
| 52 Week High | 41.05 |
| 52 Week Low | 22.68 |
| Beta | 1.30 |
| 20 Day Moving Average | 47,156.80 |
| Target Price Consensus | N/A |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -5.99 | 4 Week | -0.53 |
| 12 Week | -10.49 | 12 Week | -1.19 |
| YTD | -5.41 | YTD | -4.34 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 10.21 | Dividend Yield | 3.15% |
| | | Annual Dividend | $0.92 |
| Market Capitalization (millions) | 297.71 | Payout Ratio | 0.00 |
| Short Ratio | 11.92 | Change in Payout Ratio | 0.00 |
| Last Split Date | 02/12/1993 | Last Dividend Payout / Amount | 10/29/2007 / $0.23 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | N/A | Current (1=Strong Buy, 5=Strong Sell) | 4.00 |
| Current Year EPS Consensus Estimate | N/A | 30 Days Ago | 4.00 |
| Estimated Long-Term EPS Growth Rate | N/A | 60 Days Ago | 4.00 |
| Next EPS Report Date | N/A | 90 Days Ago | 3.00 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | - | vs. Previous Year | -37.88% | vs. Previous Year | -0.92% |
| Trailing 12 Months: | 18.58 | vs. Previous Quarter | 925.00% | vs. Previous Quarter: | 2.32% |
| PEG Ratio | - | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.63 | 09/30/07 | - | 09/30/07 | - |
| Price/Cash Flow | 8.54 | 06/30/07 | 9.18 | 06/30/07 | 3.28 |

| | | | | | |
|---|---|---|---|---|---|
| Price / Sales | - | 03/31/07 | 10.81 | 03/31/07 | 3.92 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | 5.05 |
| 03/31/07 | - | 03/31/07 | - | 03/31/07 | 5.85 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | - |
| 03/31/07 | - | 03/31/07 | - | 03/31/07 | - |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | - |
| 03/31/07 | - | 03/31/07 | - | 03/31/07 | - |

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## CLECO CP(HLDG CO) (NYSE)

Scottrade

| CNL | 27.07 | ▼-0.46 | (-1.67%) | Vol. 188,492 | 12:24 ET |
|---|---|---|---|---|---|

Cleco Corporation holds investments in several subsidiaries, including Utility Group, Cleco Midstream Resources LLC and Utility Construction & Technology Solutions LLC. Utility Group, incorporated on January 2, 1935 under the laws of the State of Louisiana, contains the LPSC jurisdictional generation, transmission and distribution electric utility operations serving the Company's traditional retail and wholesale customers. Utility Group serves customers in communities and rural areas in the State of Louisiana.

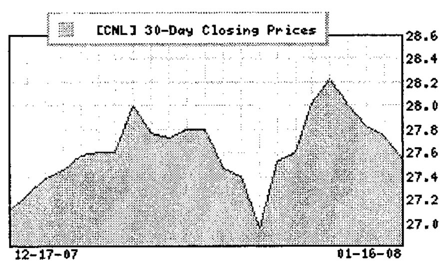
### General Information

CLECO CORP
2030 Donahue Ferry Road
Pineville, LA 71360-5226
Phone: 318 484-7400
Fax: 318 484-7465
Web: www.cleco.com
Email: None

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 03/04/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | 2 |
| Yesterday's Close | 27.53 |
| 52 Week High | 29.84 |
| 52 Week Low | 22.14 |
| Beta | 1.21 |
| 20 Day Moving Average | 473,498.00 |
| Target Price Consensus | 29.75 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 0.55 | 4 Week | 6.39 |
| 12 Week | 10.03 | 12 Week | 21.47 |
| YTD | -0.97 | YTD | 5.56 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 60.01 | Dividend Yield | 3.27% |
| | | Annual Dividend | $0.90 |
| Market Capitalization (millions) | 1,651.99 | Payout Ratio | 0.00 |
| Short Ratio | 8.56 | Change in Payout Ratio | 0.00 |
| Last Split Date | 05/22/2001 | Last Dividend Payout / Amount | 10/25/2007 / $0.22 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.21 | Current (1=Strong Buy, 5=Strong Sell) | 2.00 |
| Current Year EPS Consensus Estimate | 1.33 | 30 Days Ago | 1.80 |
| Estimated Long-Term EPS Growth Rate | 9.50 | 60 Days Ago | 2.00 |
| Next EPS Report Date | 03/04/2008 | 90 Days Ago | 1.67 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 15.16 | vs. Previous Year | 46.94% | vs. Previous Year | 5.98% |
| Trailing 12 Months: | 21.34 | vs. Previous Quarter | 188.00% | vs. Previous Quarter: | 19.19% |
| PEG Ratio | 1.60 | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.73 | 09/30/07 | - | 09/30/07 | - |
| Price/Cash Flow | 21.20 | 06/30/07 | 8.70 | 06/30/07 | 3.89 |
| Price / Sales | - | 03/31/07 | 6.99 | 03/31/07 | 2.97 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | 7.67 |
| 03/31/07 | 1.10 | 03/31/07 | 0.92 | 03/31/07 | 6.22 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | - |
| 03/31/07 | 12.76 | 03/31/07 | 12.76 | 03/31/07 | 15.94 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | - |
| 03/31/07 | -0.58 | 03/31/07 | 0.68 | 03/31/07 | 40.38 |

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## CONS EDISON INC (NYSE)

Scottrade

| | | | | | |
|---|---|---|---|---|---|
| ED | 42.74 | ▼-0.05 | (-0.12%) | Vol. 965,012 | 12:33 ET |

Consolidated Edison, Inc. is one of the nation's largest investor-owned energy companies. The company provides a wide range of energy- related products and services to its customers through regulated utility subsidiaries and competitive energy and telecommunications businesses.

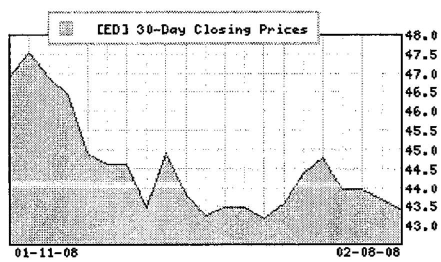
### General Information

CONSOL EDISON
4 Irving Place
New York, NY 10003
Phone: 212 460-4600
Fax: 212 475-0734
Web: www.conedison.com
Email: investor.conedison.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 05/08/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | 2 |
| Yesterday's Close | 42.78 |
| 52 Week High | 52.90 |
| 52 Week Low | 42.46 |
| Beta | 0.49 |
| 20 Day Moving Average | 2,809,663.50 |
| Target Price Consensus | 46.68 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -7.57 | 4 Week | -2.72 |
| 12 Week | -7.39 | 12 Week | 1.48 |
| YTD | -11.22 | YTD | -2.08 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 271.52 | Dividend Yield | 5.35% |
| | | Annual Dividend | $2.32 |
| Market Capitalization (millions) | 11,775.65 | Payout Ratio | 0.66 |
| Short Ratio | 3.36 | Change in Payout Ratio | -0.11 |
| Last Split Date | 07/03/1989 | Last Dividend Payout / Amount | NA / $0.00 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 1.03 | Current (1=Strong Buy, 5=Strong Sell) | 2.98 |
| Current Year EPS Consensus Estimate | 3.20 | 30 Days Ago | 2.98 |
| Estimated Long-Term EPS Growth Rate | 3.20 | 60 Days Ago | 2.98 |
| Next EPS Report Date | 05/08/2008 | 90 Days Ago | 2.89 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.53 | vs. Previous Year | -2.56% | vs. Previous Year | 5.78% |
| Trailing 12 Months: | 12.32 | vs. Previous Quarter | -33.91% | vs. Previous Quarter: | 20.13% |
| PEG Ratio | 4.27 | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 1.31 | 12/31/07 | 10.83 | 12/31/07 | 3.45 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 8.20 | 09/30/07 | 10.97 | 09/30/07 | 3.44 |
| Price / Sales | - | 06/30/07 | 10.35 | 06/30/07 | 3.19 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 0.89 | 09/30/07 | 0.75 | 09/30/07 | 7.23 |
| 06/30/07 | 0.88 | 06/30/07 | 0.75 | 06/30/07 | 6.70 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 10.51 | 09/30/07 | 10.51 | 09/30/07 | 33.18 |
| 06/30/07 | 10.05 | 06/30/07 | 10.05 | 06/30/07 | 32.55 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 16.42 | 09/30/07 | 0.89 | 09/30/07 | 46.72 |
| 06/30/07 | 16.15 | 06/30/07 | 0.89 | 06/30/07 | 46.52 |

**Zacks.com Quotes and Research**

## D T E ENERGY CO HLDG (NYSE)

| | | | | | |
|---|---|---|---|---|---|
| DTE | 44.00 | -0.37 | (-0.83%) | Vol. 607,500 | 12:31 ET |

DTE Energy is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Its largest operating units are Detroit Edison, an electric utility serving 2.1 million customers in Southeastern Michigan, and MichCon, a natural gas utility serving 1.2 million customers in Michigan. Detroit Edison is the Company's principal operating subsidiary. Affiliates of the Company are engaged in non-regulated businesses, including energy-related services and products.

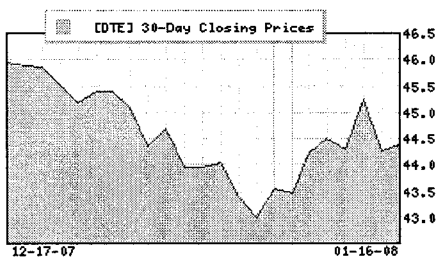
### General Information

DTE ENERGY CO
2000 2nd Avenue
Detroit, MI 48226-1279
Phone: 313 235-4000
Fax: 313-235-6743
Web: www.dteenergy.com
Email: None

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 03/10/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 44.37 |
| 52 Week High | 54.74 |
| 52 Week Low | 43.00 |
| Beta | 0.69 |
| 20 Day Moving Average | 1,494,765.88 |
| Target Price Consensus | 50.67 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -3.23 | 4 Week | 2.40 |
| 12 Week | -7.49 | 12 Week | 2.13 |
| YTD | 0.93 | YTD | 5.62 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 163.71 | Dividend Yield | 4.78% |
| | | Annual Dividend | $2.12 |
| Market Capitalization (millions) | 7,263.99 | Payout Ratio | 0.00 |
| Short Ratio | 4.24 | Change in Payout Ratio | 0.00 |
| Last Split Date | N/A | Last Dividend Payout / Amount | 12/13/2007 / $0.53 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.76 | Current (1=Strong Buy, 5=Strong Sell) | 3.13 |
| Current Year EPS Consensus Estimate | 2.59 | 30 Days Ago | 3.13 |
| Estimated Long-Term EPS Growth Rate | 6.00 | 60 Days Ago | 3.13 |
| Next EPS Report Date | 03/10/2008 | 90 Days Ago | 3.11 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.80 | vs. Previous Year | 4.81% | vs. Previous Year | 10.06% |
| Trailing 12 Months: | 13.17 | vs. Previous Quarter | 84.75% | vs. Previous Quarter: | 23.69% |
| PEG Ratio | 2.47 | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.33 | 09/30/07 | - | 09/30/07 | - |
| Price/Cash Flow | 5.07 | 06/30/07 | 10.02 | 06/30/07 | 2.45 |
| Price / Sales | - | 03/31/07 | 10.03 | 03/31/07 | 2.51 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 0.94 | 06/30/07 | 0.75 | 06/30/07 | 6.20 |
| 03/31/07 | 1.04 | 03/31/07 | 0.87 | 03/31/07 | 6.40 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 10.88 | 06/30/07 | 10.88 | 06/30/07 | 33.38 |
| 03/31/07 | 11.48 | 03/31/07 | 11.48 | 03/31/07 | 33.45 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 4.91 | 06/30/07 | 1.17 | 06/30/07 | 54.08 |
| 03/31/07 | 4.63 | 03/31/07 | 1.19 | 03/31/07 | 55.52 |

**ZACKS** INVESTMENT RESEARCH
*Proven Ratings, Research & Recommendations*
**Zacks.com Quotes and Research**

## EMPIRE DISTRICT ELCT (NYSE)

Scottrade

| | | | | | |
|---|---|---|---|---|---|
| EDE | 22.05 | ▼-0.21 | (-0.94%) | Vol. 88,630 | 12:37 ET |

The Empire District Electric Company is an operating public utility engagedin the generation, purchase, transmission, distribution and sale ofelectricity in parts of Missouri, Kansas, Oklahoma and Arkansas. TheCompany also provides water service to several towns in Missouri.

### General Information

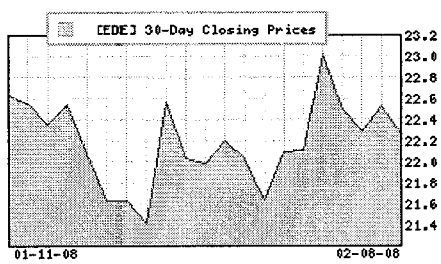
EMPIRE DISTRICT
602 Joplin Street
Joplin, MO 64801
Phone: 417 625-5100
Fax: 417 625-5173
Web: www.empiredistrict.com
Email: jwatson@empiredistrict.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 04/24/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 22.26 |
| 52 Week High | 26.13 |
| 52 Week Low | 21.09 |
| Beta | 0.84 |
| 20 Day Moving Average | 224,398.05 |
| Target Price Consensus | 24.25 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -1.63 | 4 Week | 3.52 |
| 12 Week | -5.76 | 12 Week | 3.26 |
| YTD | -2.28 | YTD | 7.78 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 33.55 | Dividend Yield | 5.75% |
| | | Annual Dividend | $1.28 |
| Market Capitalization (millions) | 746.89 | Payout Ratio | 1.23 |
| Short Ratio | 10.58 | Change in Payout Ratio | 0.07 |
| Last Split Date | 01/30/1992 | Last Dividend Payout / Amount | 11/28/2007 / $0.32 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.15 | Current (1=Strong Buy, 5=Strong Sell) | 2.20 |
| Current Year EPS Consensus Estimate | 1.40 | 30 Days Ago | 2.00 |
| Estimated Long-Term EPS Growth Rate | - | 60 Days Ago | 2.00 |
| Next EPS Report Date | 04/24/2008 | 90 Days Ago | 2.00 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 15.87 | vs. Previous Year | -103.33% | vs. Previous Year | 8.29% |
| Trailing 12 Months: | 21.40 | vs. Previous Quarter | -101.32% | vs. Previous Quarter: | 32.49% |
| PEG Ratio | - | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.41 | 12/31/07 | 6.70 | 12/31/07 | 2.27 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 8.14 | 09/30/07 | 8.71 | 09/30/07 | 2.99 |
| Price / Sales | - | 06/30/07 | 8.58 | 06/30/07 | 3.01 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 0.89 | 09/30/07 | 0.58 | 09/30/07 | 8.50 |
| 06/30/07 | 0.94 | 06/30/07 | 0.59 | 06/30/07 | 8.52 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 8.27 | 09/30/07 | 8.27 | 09/30/07 | 15.73 |
| 06/30/07 | 8.40 | 06/30/07 | 8.40 | 06/30/07 | 15.44 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 5.23 | 09/30/07 | 1.13 | 09/30/07 | 53.06 |
| 06/30/07 | 4.75 | 06/30/07 | 1.16 | 06/30/07 | 53.62 |

**Zacks.com Quotes and Research**

| **FIRSTENERGY CP** (NYSE) | | | | Scottrade |
|---|---|---|---|---|
| FE 74.24 | ▼-1.57 | (-2.07%) | Vol. 1,142,983 | 12:41 ET |

FirstEnergy Corp. is a diversified energy services holding company as the result of the merger of Ohio Edison Company and Centerior Energy Corporation. FirstEnergy companies provide electricity and natural gas services and a wide array of energy-related products and services. FirstEnergy's four electric utility companies, Ohio Edison and its Pennsylvania Power subsidiary, The Illuminating Company and Toledo Edison, serve customers in northern and central Ohio and western Pennsylvania. (Company Press Release)

## General Information

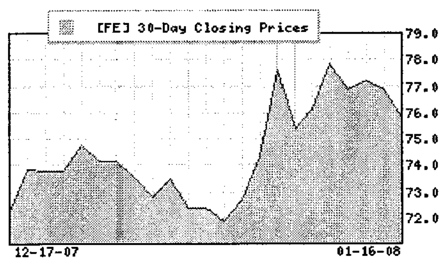
FIRSTENERGY CP
76 South Main Street
Akron, OH 44308
Phone: 800 736-3402
Fax: -
Web: www.firstenergycorp.com
Email: turoskyk@firstenergycorp.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/19/2008 |

## Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 75.81 |
| 52 Week High | 78.51 |
| 52 Week Low | 57.83 |
| Beta | 0.41 |
| 20 Day Moving Average | 1,845,050.75 |
| Target Price Consensus | 77.94 |




### % Price Change

| | |
|---|---|
| 4 Week | 2.72 |
| 12 Week | 14.73 |
| YTD | 4.80 |

### % Price Change Relative to S&P 500

| | |
|---|---|
| 4 Week | 8.69 |
| 12 Week | 26.65 |
| YTD | 11.37 |

### Share Information

| | |
|---|---|
| Shares Outstanding (millions) | 304.83 |
| Market Capitalization (millions) | 23,109.54 |
| Short Ratio | 2.58 |
| Last Split Date | N/A |

### Dividend Information

| | |
|---|---|
| Dividend Yield | 2.64% |
| Annual Dividend | $2.00 |
| Payout Ratio | 0.00 |
| Change in Payout Ratio | 0.00 |
| Last Dividend Payout / Amount | 11/05/2007 / $0.50 |

### EPS Information

| | |
|---|---|
| Current Quarter EPS Consensus Estimate | 0.91 |
| Current Year EPS Consensus Estimate | 4.20 |
| Estimated Long-Term EPS Growth Rate | 7.50 |
| Next EPS Report Date | 02/19/2008 |

### Consensus Recommendations

| | |
|---|---|
| Current (1=Strong Buy, 5=Strong Sell) | 1.88 |
| 30 Days Ago | 1.75 |
| 60 Days Ago | 1.75 |
| 90 Days Ago | 2.00 |

## Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 17.73 | vs. Previous Year | -4.96% | vs. Previous Year | 5.88% |
| Trailing 12 Months: | 18.18 | vs. Previous Quarter | 19.64% | vs. Previous Quarter: | 16.13% |
| PEG Ratio | 2.36 | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 2.67 | 09/30/07 | - | 09/30/07 | - |
| Price/Cash Flow | 8.90 | 06/30/07 | 15.11 | 06/30/07 | 4.13 |
| Price / Sales | - | 03/31/07 | 15.38 | 03/31/07 | 4.25 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | 10.60 |
| 03/31/07 | 0.40 | 03/31/07 | 0.31 | 03/31/07 | 11.13 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | - |
| 03/31/07 | 18.31 | 03/31/07 | 18.31 | 03/31/07 | 28.34 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | - |
| 03/31/07 | 7.86 | 03/31/07 | 1.01 | 03/31/07 | 50.29 |

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**Zacks.com Quotes and Research**

## HAWAIIAN ELEC INDS (NYSE)

Scottrade

| HE | 22.35 | ▲0.05 | (0.22%) | Vol. 207,500 | 12:44 ET |
|---|---|---|---|---|---|

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

### General Information

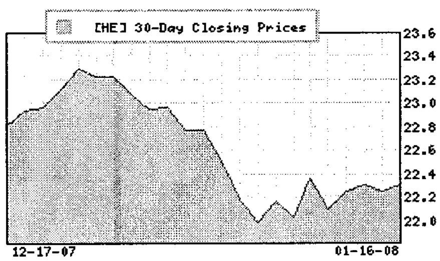
HAWAIIAN ELEC
900 Richards Street
Honolulu, HI 96813
Phone: 808 543-5662
Fax: 808 543-7966
Web: www.hei.com
Email: shollinger@hei.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/22/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 22.30 |
| 52 Week High | 27.42 |
| 52 Week Low | 20.25 |
| Beta | 0.60 |
| 20 Day Moving Average | 287,359.31 |
| Target Price Consensus | 22.2 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -2.92 | 4 Week | 2.72 |
| 12 Week | 0.09 | 12 Week | 10.49 |
| YTD | -2.06 | YTD | 2.37 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 83.04 | Dividend Yield | 5.56% |
| | | Annual Dividend | $1.24 |
| Market Capitalization (millions) | 1,851.81 | Payout Ratio | 0.00 |
| Short Ratio | 12.70 | Change in Payout Ratio | 0.00 |
| Last Split Date | 06/14/2004 | Last Dividend Payout / Amount | 11/13/2007 / $0.31 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.32 | Current (1=Strong Buy, 5=Strong Sell) | 3.20 |
| Current Year EPS Consensus Estimate | 0.98 | 30 Days Ago | 3.20 |
| Estimated Long-Term EPS Growth Rate | 4.50 | 60 Days Ago | 3.20 |
| Next EPS Report Date | 02/22/2008 | 90 Days Ago | 3.60 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.91 | vs. Previous Year | -15.00% | vs. Previous Year | -0.06% |
| Trailing 12 Months: | 24.24 | vs. Previous Quarter | 61.90% | vs. Previous Quarter: | 12.10% |
| PEG Ratio | 3.31 | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 1.63 | 09/30/07 | - | 09/30/07 | - |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 6.98 | 06/30/07 | 6.82 | 06/30/07 | 0.76 |
| Price / Sales | - | 03/31/07 | 7.02 | 03/31/07 | 0.80 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 0.24 | 06/30/07 | 0.24 | 06/30/07 | 3.10 |
| 03/31/07 | 0.24 | 03/31/07 | 0.24 | 03/31/07 | 3.27 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 3.77 | 06/30/07 | 3.77 | 06/30/07 | 13.70 |
| 03/31/07 | 4.60 | 03/31/07 | 4.60 | 03/31/07 | 13.52 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | 1.09 | 06/30/07 | 52.79 |
| 03/31/07 | - | 03/31/07 | 1.11 | 03/31/07 | 53.30 |

**Zacks.com Quotes and Research**

## IDACORP INC HLDG CO (NYSE)

| IDA | 33.93 | ▼-0.16 | (-0.47%) | Vol. 219,400 | 12:46 ET |
|---|---|---|---|---|---|

Idacorp Inc. is an electric public utility company. The company is engaged in the generation, purchase, transmission, distribution and sale of electric energy primarily in the areas including southern Idaho, eastern Oregon and northern Nevada. The company relies heavily on hydroelectric power for its generating needs and is one of the nation's few investor-owned utilities with a predominantly hydro base. The company's principal commercial and industrial customers include lodges, condominiums, and ski lifts and related facilities.

### General Information

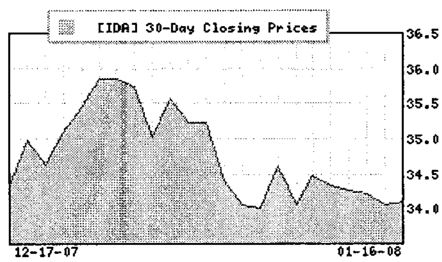
IDACORP INC
1221 West Idaho Street
Boise, ID 83702-5627
Phone: 208 388-2200
Fax: 208 388-6916
Web: www.idacorpinc.com
Email: LSpencer@idacorpinc.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/14/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 34.09 |
| 52 Week High | 38.39 |
| 52 Week Low | 30.07 |
| Beta | 0.80 |
| 20 Day Moving Average | 416,759.00 |
| Target Price Consensus | 35.67 |




**% Price Change**

| | |
|---|---|
| 4 Week | -1.59 |
| 12 Week | 3.46 |
| YTD | -3.21 |

**% Price Change Relative to S&P 500**

| | |
|---|---|
| 4 Week | 4.13 |
| 12 Week | 14.21 |
| YTD | 1.95 |

**Share Information**

| | |
|---|---|
| Shares Outstanding (millions) | 44.99 |
| Market Capitalization (millions) | 1,533.88 |
| Short Ratio | 12.36 |
| Last Split Date | N/A |

**Dividend Information**

| | |
|---|---|
| Dividend Yield | 3.52% |
| Annual Dividend | $1.20 |
| Payout Ratio | 0.00 |
| Change in Payout Ratio | 0.00 |
| Last Dividend Payout / Amount | 11/01/2007 / $0.30 |

### EPS Information

| | |
|---|---|
| Current Quarter EPS Consensus Estimate | 0.21 |
| Current Year EPS Consensus Estimate | 1.82 |
| Estimated Long-Term EPS Growth Rate | 5.00 |
| Next EPS Report Date | 02/14/2008 |

### Consensus Recommendations

| | |
|---|---|
| Current (1=Strong Buy, 5=Strong Sell) | 3.25 |
| 30 Days Ago | 3.25 |
| 60 Days Ago | 3.25 |
| 90 Days Ago | 3.25 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 15.76 | vs. Previous Year | -14.47% | vs. Previous Year | 13.42% |
| Trailing 12 Months: | 16.63 | vs. Previous Quarter | 54.76% | vs. Previous Quarter: | 22.31% |
| PEG Ratio | 3.15 | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.28 | 09/30/07 | - | 09/30/07 | - |
| Price/Cash Flow | 6.57 | 06/30/07 | 7.84 | 06/30/07 | 2.60 |
| Price / Sales | - | 03/31/07 | 8.26 | 03/31/07 | 2.73 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | 10.39 |
| 03/31/07 | 0.84 | 03/31/07 | 0.67 | 03/31/07 | 11.20 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | - |
| 03/31/07 | 12.51 | 03/31/07 | 12.51 | 03/31/07 | 26.59 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | - | 06/30/07 | - | 06/30/07 | - |
| 03/31/07 | 5.74 | 03/31/07 | 0.91 | 03/31/07 | 47.65 |

**Zacks.com Quotes and Research**

| MGE ENERGY INC. (NASDAQ) | | | | | Scottrade |
|---|---|---|---|---|---|
| MGEE | 33.75 | ▼-0.88 | (-2.54%) | Vol. 41,499 | 12:55 ET |

MGE Energy is a public utility holding company. Its principal subsidiary, MGE, generates and distributes electricity to more than 128,000 customers in Dane County, Wisconsin (250 square miles) and purchases, transports and distributes natural gas to nearly 123,000 customers in seven south-central and western Wisconsin counties (1,375 square miles). (Press Release)

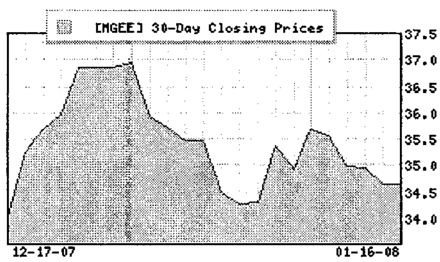
## General Information

MGE ENERGY INC
133 South Blair St
Madison, WI 53703
Phone: 608 252-7000
Fax: 608 252-7098
Web: www.mge.com
Email: investor@mgeenergy.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | N/A |

## Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 34.63 |
| 52 Week High | 37.24 |
| 52 Week Low | 29.40 |
| Beta | 0.77 |
| 20 Day Moving Average | 78,566.10 |
| Target Price Consensus | N/A |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -2.97 | 4 Week | 2.67 |
| 12 Week | 4.21 | 12 Week | 15.04 |
| YTD | -2.37 | YTD | 3.33 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 21.87 | Dividend Yield | 4.10% |
| | | Annual Dividend | $1.42 |
| Market Capitalization (millions) | 757.32 | Payout Ratio | 0.00 |
| Short Ratio | 21.30 | Change in Payout Ratio | 0.00 |
| Last Split Date | 02/21/1996 | Last Dividend Payout / Amount | 11/28/2007 / $0.35 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | N/A | Current (1=Strong Buy, 5=Strong Sell) | 3.00 |
| Current Year EPS Consensus Estimate | N/A | 30 Days Ago | 0.00 |
| Estimated Long-Term EPS Growth Rate | N/A | 60 Days Ago | 0.00 |
| Next EPS Report Date | N/A | 90 Days Ago | 0.00 |

## Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | - | vs. Previous Year | 14.52% | vs. Previous Year | 5.13% |
| Trailing 12 Months: | 14.99 | vs. Previous Quarter | 51.06% | vs. Previous Quarter: | 5.21% |
| PEG Ratio | - | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.79 | 09/30/07 | - | 09/30/07 | - |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 9.63 | 06/30/07 | 12.31 | 06/30/07 | 4.89 |
| Price / Sales | - | 03/31/07 | 12.06 | 03/31/07 | 4.75 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 0.80 | 06/30/07 | 0.49 | 06/30/07 | 9.17 |
| 03/31/07 | 1.06 | 03/31/07 | 0.69 | 03/31/07 | 8.74 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 14.47 | 06/30/07 | 14.47 | 06/30/07 | 19.31 |
| 03/31/07 | 13.84 | 03/31/07 | 13.84 | 03/31/07 | 19.26 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 6.03 | 06/30/07 | 0.55 | 06/30/07 | 35.61 |
| 03/31/07 | 5.96 | 03/31/07 | 0.58 | 03/31/07 | 36.74 |

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## NISOURCE INC HLDG CO (NYSE)

Scottrade

| | | | | | |
|---|---|---|---|---|---|
| NI | 18.41 | ▼-0.16 | (-0.86%) | Vol. 717,630 | 12:41 ET |

NiSource Inc., formerly NIPSCO Industries, Inc., is an energyand utility-based holding company headquartered in Merrillville, Indiana, that provides natural gas, electricity and water to the public for residential, commercial and industrial uses. NiSource operating companies deliver energy to millions of customers located within the high-demand energy corridor stretching from the Gulf Coast through the Midwest to New England.

### General Information

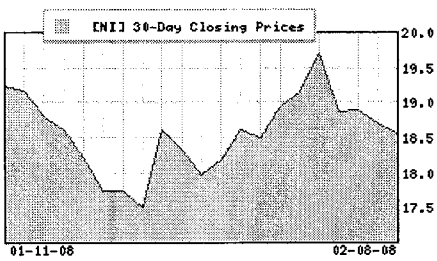
NISOURCE INC
801 East 86th Avenue
Merrillville, IN 46410
Phone: 877 647-5990
Fax: 219-647-5589
Web: www.nisource.com
Email: questions@nisource.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 05/08/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 18.57 |
| 52 Week High | 25.43 |
| 52 Week Low | 16.78 |
| Beta | 0.45 |
| 20 Day Moving Average | 2,779,183.00 |
| Target Price Consensus | 21.13 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -3.48 | 4 Week | 1.57 |
| 12 Week | 3.34 | 12 Week | 13.23 |
| YTD | -1.69 | YTD | 8.43 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 274.17 | Dividend Yield | 4.95% |
| | | Annual Dividend | $0.92 |
| Market Capitalization (millions) | 5,091.38 | Payout Ratio | 0.67 |
| Short Ratio | 3.72 | Change in Payout Ratio | 0.05 |
| Last Split Date | 02/23/1998 | Last Dividend Payout / Amount | 01/29/2008 / $0.23 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.81 | Current (1=Strong Buy, 5=Strong Sell) | 3.10 |
| Current Year EPS Consensus Estimate | 1.31 | 30 Days Ago | 3.10 |
| Estimated Long-Term EPS Growth Rate | 2.80 | 60 Days Ago | 3.10 |
| Next EPS Report Date | 05/08/2008 | 90 Days Ago | 3.11 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.15 | vs. Previous Year | 0.00% | vs. Previous Year | 9.81% |
| Trailing 12 Months: | 13.56 | vs. Previous Quarter | 437.50% | vs. Previous Quarter: | 259.40% |
| PEG Ratio | 5.15 | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 1.02 | 12/31/07 | 7.48 | 12/31/07 | 2.16 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 5.36 | 09/30/07 | 7.47 | 09/30/07 | 2.13 |
| Price / Sales | 0.92 | 06/30/07 | 7.66 | 06/30/07 | 2.17 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 6.86 |
| 09/30/07 | 0.84 | 09/30/07 | 0.50 | 09/30/07 | 7.09 |
| 06/30/07 | 0.66 | 06/30/07 | 0.53 | 06/30/07 | 7.20 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 10.02 | 09/30/07 | 10.02 | 09/30/07 | 18.25 |
| 06/30/07 | 10.50 | 06/30/07 | 10.50 | 06/30/07 | 18.52 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 7.20 | 09/30/07 | 1.18 | 09/30/07 | 54.21 |
| 06/30/07 | 7.37 | 06/30/07 | 1.01 | 06/30/07 | 50.24 |

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## NSTAR (NYSE)



| NST | 31.64 | ▼-0.50 | (-1.56%) | Vol. 197,736 | 12:43 ET |
|---|---|---|---|---|---|

NSTAR was formed through a merger of BEC Energy and Commonwealth Energy System. The company, headquartered in Boston, Massachusetts provides regulated electric and gas utility services and is also engaged intelecommunications and other non-regulated activities. NSTAR, through its subsidiaries, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and Commonwealth Gas Company, serves approximately 1.3 million customers throughout Massachusetts. (Press Release)

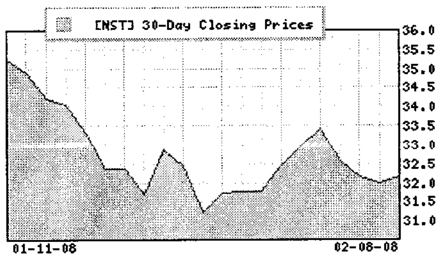
### General Information

NSTAR
800 Boylston Street
Boston, MA 02199
Phone: 617 424-2000
Fax: 617 424-4032
Web: www.nstaronline.com
Email: ir@nstar.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 04/24/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 32.14 |
| 52 Week High | 37.37 |
| 52 Week Low | 30.14 |
| Beta | 0.71 |
| 20 Day Moving Average | 609,503.50 |
| Target Price Consensus | 35.78 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -8.82 | 4 Week | -4.05 |
| 12 Week | -7.11 | 12 Week | 1.78 |
| YTD | -11.26 | YTD | -2.13 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 106.81 | Dividend Yield | 4.36% |
| | | Annual Dividend | $1.40 |
| Market Capitalization (millions) | 3,432.81 | Payout Ratio | 0.63 |
| Short Ratio | 5.59 | Change in Payout Ratio | -0.01 |
| Last Split Date | 06/06/2005 | Last Dividend Payout / Amount | 01/08/2008 / $0.35 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.48 | Current (1=Strong Buy, 5=Strong Sell) | 2.43 |
| Current Year EPS Consensus Estimate | 2.23 | 30 Days Ago | 2.38 |
| Estimated Long-Term EPS Growth Rate | 6.20 | 60 Days Ago | 2.38 |
| Next EPS Report Date | 04/24/2008 | 90 Days Ago | 2.29 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.43 | vs. Previous Year | -2.63% | vs. Previous Year | -6.82% |
| Trailing 12 Months: | 15.45 | vs. Previous Quarter | -53.16% | vs. Previous Quarter: | -7.15% |
| PEG Ratio | 2.33 | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 2.02 | 12/31/07 | 13.31 | 12/31/07 | 2.89 |
| Price/Cash Flow | 6.02 | 09/30/07 | 13.53 | 09/30/07 | 2.89 |
| Price / Sales | 1.05 | 06/30/07 | 13.31 | 06/30/07 | 2.80 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 6.79 |
| 09/30/07 | 0.72 | 09/30/07 | 0.63 | 09/30/07 | 6.71 |
| 06/30/07 | 0.72 | 06/30/07 | 0.65 | 06/30/07 | 6.20 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 10.58 | 09/30/07 | 10.58 | 09/30/07 | 15.92 |
| 06/30/07 | 9.77 | 06/30/07 | 9.77 | 06/30/07 | 15.44 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 18.09 | 09/30/07 | 1.01 | 09/30/07 | 50.28 |
| 06/30/07 | 19.22 | 06/30/07 | 1.04 | 06/30/07 | 50.42 |

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## PNM RES INC (HLDG) (NYSE)

Scottrade

| | | | | | |
|---|---|---|---|---|---|
| PNM | 20.06 | -0.08 | (-0.40%) | Vol. 779,500 | 13:01 ET |

PNM Resources is an energy holding company based in Albuquerque, New Mexico. Its principal subsidiary is Public Service Company of New Mexico, which provides electric power and natural gas utility services to more than 1.3 million people in New Mexico. The company also sells power on the wholesale market in the Western U.S.

### General Information

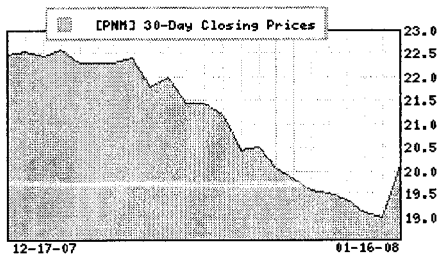
PNM RESOURCES
Alvarado Square
Albuquerque, NM 87158
Phone: 505 241-2700
Fax: 505 241-4311
Web: www.pnmresources.com
Email: None

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/12/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 20.14 |
| 52 Week High | 34.28 |
| 52 Week Low | 18.75 |
| Beta | 0.89 |
| 20 Day Moving Average | 1,421,115.00 |
| Target Price Consensus | 24.33 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -10.29 | 4 Week | -5.08 |
| 12 Week | -14.81 | 12 Week | -5.95 |
| YTD | -6.11 | YTD | -5.36 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 76.78 | Dividend Yield | 4.57% |
| | | Annual Dividend | $0.92 |
| Market Capitalization (millions) | 1,546.29 | Payout Ratio | 0.00 |
| Short Ratio | 10.36 | Change in Payout Ratio | 0.00 |
| Last Split Date | 06/14/2004 | Last Dividend Payout / Amount | 10/30/2007 / $0.23 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.31 | Current (1=Strong Buy, 5=Strong Sell) | 2.43 |
| Current Year EPS Consensus Estimate | 1.27 | 30 Days Ago | 2.71 |
| Estimated Long-Term EPS Growth Rate | 8.50 | 60 Days Ago | 2.57 |
| Next EPS Report Date | 02/12/2008 | 90 Days Ago | 2.57 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 11.63 | vs. Previous Year | -34.92% | vs. Previous Year | -3.19% |
| Trailing 12 Months: | 13.89 | vs. Previous Quarter | 215.38% | vs. Previous Quarter: | 8.40% |
| PEG Ratio | 1.37 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 0.90 | 09/30/07 | - | 09/30/07 | - |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 5.04 | 06/30/07 | 6.49 | 06/30/07 | 1.85 |
| Price / Sales | - | 03/31/07 | 7.59 | 03/31/07 | 2.06 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 0.40 | 06/30/07 | 0.36 | 06/30/07 | 4.46 |
| 03/31/07 | 0.58 | 03/31/07 | 0.53 | 03/31/07 | 4.92 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 4.02 | 06/30/07 | 4.02 | 06/30/07 | 22.26 |
| 03/31/07 | 6.15 | 03/31/07 | 6.15 | 03/31/07 | 22.51 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 27.13 | 06/30/07 | 0.72 | 06/30/07 | 41.79 |
| 03/31/07 | 26.05 | 03/31/07 | 0.89 | 03/31/07 | 46.85 |

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## PINNACLE WEST CAP (NYSE)

| | | | | | |
|---|---|---|---|---|---|
| PNW | 37.05 | ▼-0.11 | (-0.30%) | Vol. 435,646 | 12:46 ET |

Pinnacle West Capital is engaged, through its subsidiaries, in the generation, transmission, and distribution of electricity and selling energy, products and services; in real estate development; and in venture capital investment. Its primary subsidiary is Arizona Public Service Company. The company's other subsidiaries include SunCor, El Dorado, APSEnergy Services and Pinnacle West Energy.

### General Information

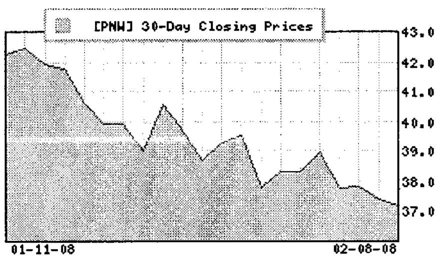
PINNACLE WEST
400 North Fifth Street
P.O. Box 53999
Phoenix, AZ 85072-3999
Phone: 602 250-1000
Fax: 602 250-2789
Web: www.pinnaclewest.com
Email: elisa.malagon@pinnaclewest.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 04/23/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 37.16 |
| 52 Week High | 50.68 |
| 52 Week Low | 36.79 |
| Beta | 0.65 |
| 20 Day Moving Average | 941,397.13 |
| Target Price Consensus | 39.22 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -12.07 | 4 Week | -7.46 |
| 12 Week | -13.38 | 12 Week | -5.09 |
| YTD | -12.38 | YTD | -3.36 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 100.39 | Dividend Yield | 5.65% |
| | | Annual Dividend | $2.10 |
| Market Capitalization (millions) | 3,730.31 | Payout Ratio | 0.73 |
| | | Change in Payout Ratio | 0.05 |
| Short Ratio | 9.46 | | |
| Last Split Date | N/A | Last Dividend Payout / Amount | 01/30/2008 / $0.52 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.16 | Current (1=Strong Buy, 5=Strong Sell) | 3.13 |
| Current Year EPS Consensus Estimate | 2.63 | 30 Days Ago | 3.13 |
| Estimated Long-Term EPS Growth Rate | 6.70 | 60 Days Ago | 3.14 |
| Next EPS Report Date | 04/23/2008 | 90 Days Ago | 3.14 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.14 | vs. Previous Year | 0.00% | vs. Previous Year | 3.98% |
| Trailing 12 Months: | 12.99 | vs. Previous Quarter | -98.41% | vs. Previous Quarter: | -37.05% |
| PEG Ratio | 2.12 | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.04 | 12/31/07 | 8.30 | 12/31/07 | 2.58 |
| Price/Cash Flow | 5.27 | 09/30/07 | 8.29 | 09/30/07 | 2.56 |
| Price / Sales | 1.06 | 06/30/07 | 8.20 | 06/30/07 | 2.50 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 8.19 |
| 09/30/07 | 0.82 | 09/30/07 | 0.68 | 09/30/07 | 8.24 |
| 06/30/07 | 0.78 | 06/30/07 | 0.65 | 06/30/07 | 8.35 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 12.81 | 09/30/07 | 12.81 | 09/30/07 | 35.58 |
| 06/30/07 | 13.02 | 06/30/07 | 13.02 | 06/30/07 | 34.15 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 8.92 | 09/30/07 | 0.90 | 09/30/07 | 47.51 |
| 06/30/07 | 9.11 | 06/30/07 | 0.94 | 06/30/07 | 48.57 |

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**Zacks.com Quotes and Research**

**PPL CORP (NYSE)** Scottrade

| PPL | 47.57 | +1.16 | (2.50%) | Vol. 2,957,212 | 12:51 ET |
|---|---|---|---|---|---|

PPL Corporation is an energy and utility holding company. PPL controls about 11,500 megawatts of generating capacity in the United States, sells energy in key U.S. markets and delivers electricity to customers in Pennsylvania, the United Kingdom and Latin America.

## General Information

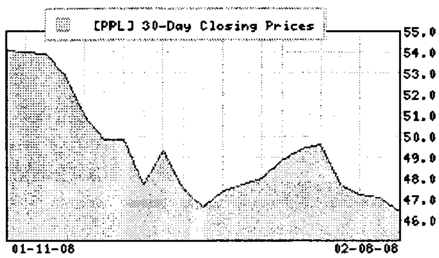
PPL CORP
Two North Ninth Street
Allentown, PA 18101-1179
Phone: 610 774-5151
Fax: 610 774-5106
Web: www.pplweb.com
Email: invrel@pplweb.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 05/08/2008 |

## Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 46.41 |
| 52 Week High | 55.23 |
| 52 Week Low | 36.46 |
| Beta | 0.37 |
| 20 Day Moving Average | 2,679,921.00 |
| Target Price Consensus | 58.44 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -14.17 | 4 Week | -9.67 |
| 12 Week | -5.57 | 12 Week | 3.46 |
| YTD | -10.90 | YTD | -1.73 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 372.20 | Dividend Yield | 2.63% |
| | | Annual Dividend | $1.22 |
| Market Capitalization (millions) | 17,273.62 | Payout Ratio | 0.47 |
| Short Ratio | 2.25 | Change in Payout Ratio | 0.00 |
| Last Split Date | 08/25/2005 | Last Dividend Payout / Amount | 12/06/2007 / $0.31 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.68 | Current (1=Strong Buy, 5=Strong Sell) | 1.78 |
| Current Year EPS Consensus Estimate | 2.42 | 30 Days Ago | 1.67 |
| Estimated Long-Term EPS Growth Rate | 10.30 | 60 Days Ago | 1.67 |
| Next EPS Report Date | 05/08/2008 | 90 Days Ago | 1.89 |

## Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 19.17 | vs. Previous Year | 27.66% | vs. Previous Year | -6.84% |
| Trailing 12 Months: | 17.85 | vs. Previous Quarter | -16.67% | vs. Previous Quarter: | -8.91% |
| PEG Ratio | 1.86 | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 3.45 | 12/31/07 | 19.12 | 12/31/07 | 5.04 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 10.99 | 09/30/07 | 18.35 | 09/30/07 | 4.82 |
| Price / Sales | 2.61 | 06/30/07 | 17.23 | 06/30/07 | 4.57 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 15.21 |
| 09/30/07 | 1.31 | 09/30/07 | 1.20 | 09/30/07 | 14.24 |
| 06/30/07 | 1.34 | 06/30/07 | 1.23 | 06/30/07 | 13.35 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 18.67 | 09/30/07 | 18.67 | 09/30/07 | 13.47 |
| 06/30/07 | 16.46 | 06/30/07 | 16.46 | 06/30/07 | 13.91 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 6.64 | 09/30/07 | 1.39 | 09/30/07 | 56.86 |
| 06/30/07 | 7.26 | 06/30/07 | 1.27 | 06/30/07 | 57.17 |

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## PROGRESS ENERGY INC (NYSE)

Scottrade

| PGN | 46.91 | ▾-0.84 | (-1.76%) | Vol. 1,213,400 | 14:33 ET |
|---|---|---|---|---|---|

CP & L Energy, Inc. is primarily engaged in the generation, transmission,distribution and sale of electricity in portions of North and South Carolina and Florida and the transmission, distribution and sale of natural gas in portions of North Carolina. The company provides these and other services through its business segments: electric, natural gas and other.

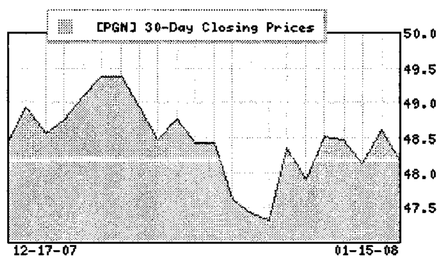
### General Information

PROGRESS ENERGY
410 South Wilmington Street
Raleigh, NC 27601-1748
Phone: 919 546-6111
Fax: 919 546-2920
Web: www.progress-energy.com
Email: investor.relations@pgnmail.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/14/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 47.75 |
| 52 Week High | 52.75 |
| 52 Week Low | 43.12 |
| Beta | 0.71 |
| 20 Day Moving Average | 1,089,392.88 |
| Target Price Consensus | 49.52 |




**% Price Change**

| | |
|---|---|
| 4 Week | -1.71 |
| 12 Week | 4.42 |
| YTD | -1.40 |

**% Price Change Relative to S&P 500**

| | |
|---|---|
| 4 Week | 4.00 |
| 12 Week | 15.27 |
| YTD | 4.16 |

**Share Information**

| | |
|---|---|
| Shares Outstanding (millions) | 259.20 |
| Market Capitalization (millions) | 12,376.90 |
| Short Ratio | 4.76 |
| Last Split Date | 02/01/1993 |

**Dividend Information**

| | |
|---|---|
| Dividend Yield | 5.15% |
| Annual Dividend | $2.46 |
| Payout Ratio | 0.00 |
| Change in Payout Ratio | 0.00 |
| Last Dividend Payout / Amount | 01/08/2008 / $0.62 |

### EPS Information

| | |
|---|---|
| Current Quarter EPS Consensus Estimate | 0.51 |
| Current Year EPS Consensus Estimate | 2.86 |
| Estimated Long-Term EPS Growth Rate | 5.20 |
| Next EPS Report Date | 02/14/2008 |

### Consensus Recommendations

| | |
|---|---|
| Current (1=Strong Buy, 5=Strong Sell) | 2.67 |
| 30 Days Ago | 2.67 |
| 60 Days Ago | 2.67 |
| 90 Days Ago | 2.75 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 15.77 | vs. Previous Year | 30.11% | vs. Previous Year | 6.42% |
| Trailing 12 Months: | 15.86 | vs. Previous Quarter | 105.08% | vs. Previous Quarter: | 28.84% |
| PEG Ratio | 3.03 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.47 | 09/30/07 | - | 09/30/07 | - |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 6.88 | 06/30/07 | 9.19 | 06/30/07 | 2.97 |
| Price / Sales | - | 03/31/07 | 8.36 | 03/31/07 | 2.68 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 1.10 | 06/30/07 | 0.79 | 06/30/07 | 7.60 |
| 03/31/07 | 0.95 | 03/31/07 | 0.60 | 03/31/07 | 6.96 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 10.83 | 06/30/07 | 10.83 | 06/30/07 | 32.54 |
| 03/31/07 | 9.61 | 03/31/07 | 9.61 | 03/31/07 | 31.95 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 4.88 | 06/30/07 | 1.09 | 06/30/07 | 52.06 |
| 03/31/07 | 4.90 | 03/31/07 | 1.02 | 03/31/07 | 50.42 |

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## SCANA CP NEW (NYSE)

Scottrade

| SCG | 39.83 | ▼-0.66 | (-1.63%) | Vol. 776,400 | 14:39 ET |
|---|---|---|---|---|---|

SCANA Corporation is an energy-based holding company whose businesses include regulated electric and natural gas utility operations, telecommunications and other non-regulated energy-related businesses. SCANA?s subsidiaries serve electric customers in South Carolina, North Carolina and Georgia.

### General Information

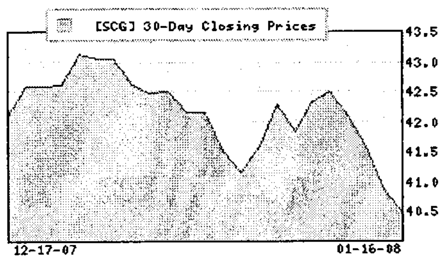
SCANA CORP
1426 Main Street
Columbia, SC 29201
Phone: 803 217-9000
Fax: 803 748-2344
Web: www.scana.com
Email: None

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/12/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 40.49 |
| 52 Week High | 45.49 |
| 52 Week Low | 32.93 |
| Beta | 0.39 |
| 20 Day Moving Average | 582,665.63 |
| Target Price Consensus | 43 |




| % Price Change | |
|---|---|
| 4 Week | -4.91 |
| 12 Week | 2.33 |
| YTD | -3.94 |

| % Price Change Relative to S&P 500 | |
|---|---|
| 4 Week | 0.62 |
| 12 Week | 12.96 |
| YTD | 4.66 |

| Share Information | |
|---|---|
| Shares Outstanding (millions) | 116.67 |
| Market Capitalization (millions) | 4,723.77 |
| Short Ratio | 2.01 |
| Last Split Date | 05/26/1995 |

| Dividend Information | |
|---|---|
| Dividend Yield | 4.35% |
| Annual Dividend | $1.76 |
| Payout Ratio | 0.00 |
| Change in Payout Ratio | 0.00 |
| Last Dividend Payout / Amount | 12/06/2007 / $0.44 |

| EPS Information | |
|---|---|
| Current Quarter EPS Consensus Estimate | 0.71 |
| Current Year EPS Consensus Estimate | 2.70 |
| Estimated Long-Term EPS Growth Rate | 5.00 |
| Next EPS Report Date | 02/12/2008 |

| Consensus Recommendations | |
|---|---|
| Current (1=Strong Buy, 5=Strong Sell) | 2.83 |
| 30 Days Ago | 2.60 |
| 60 Days Ago | 2.60 |
| 90 Days Ago | 2.67 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.99 | vs. Previous Year | 3.95% | vs. Previous Year | 1.60% |
| Trailing 12 Months: | 15.45 | vs. Previous Quarter | 68.09% | vs. Previous Quarter: | 7.15% |
| PEG Ratio | 2.80 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.61 | 09/30/07 | - | 09/30/07 | - |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 6.97 | 06/30/07 | 10.55 | 06/30/07 | 3.14 |
| Price / Sales | - | 03/31/07 | 10.55 | 03/31/07 | 3.14 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 0.81 | 06/30/07 | 0.49 | 06/30/07 | 6.61 |
| 03/31/07 | 0.84 | 03/31/07 | 0.53 | 03/31/07 | 6.57 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 9.44 | 06/30/07 | 9.44 | 06/30/07 | 25.11 |
| 03/31/07 | 8.91 | 03/31/07 | 8.91 | 03/31/07 | 24.81 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 7.02 | 06/30/07 | 1.01 | 06/30/07 | 49.28 |
| 03/31/07 | 7.17 | 03/31/07 | 1.02 | 03/31/07 | 49.66 |

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## SOUTHERN CO (NYSE)

Scottrade

| SO | 35.65 | ▾-0.10 | (-0.28%) | Vol. 1,803,047 | 12:58 ET |
|---|---|---|---|---|---|

Southern Energy acquires, develops, builds, owns and operates power production and delivery facilities and provides a broad range ofenergy-related services to utilities and industrial companies in selectedcountries around the world. Southern Energy businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

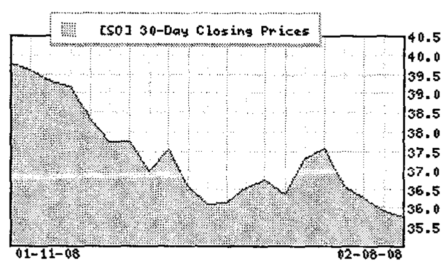
### General Information

SOUTHN COMPANY
30 Ivan Allen Jr. Boulevard, N.W.
Atlanta, GA 30308
Phone: 404 506-5000
Fax: -
Web: www.southerncompany.com
Email: investors@southerncompany.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 04/24/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 35.75 |
| 52 Week High | 40.60 |
| 52 Week Low | 33.16 |
| Beta | 0.40 |
| 20 Day Moving Average | 5,707,479.00 |
| Target Price Consensus | 37.78 |




**% Price Change**

| | |
|---|---|
| 4 Week | -10.09 |
| 12 Week | -3.43 |
| YTD | -7.74 |

**% Price Change Relative to S&P 500**

| | |
|---|---|
| 4 Week | -5.38 |
| 12 Week | 5.81 |
| YTD | 1.76 |

**Share Information**

| | |
|---|---|
| Shares Outstanding (millions) | 759.48 |
| Market Capitalization (millions) | 27,151.38 |
| Short Ratio | 4.39 |
| Last Split Date | 03/01/1994 |

**Dividend Information**

| | |
|---|---|
| Dividend Yield | 4.50% |
| Annual Dividend | $1.61 |
| Payout Ratio | 0.72 |
| Change in Payout Ratio | 0.00 |
| Last Dividend Payout / Amount | 01/31/2008 / $0.40 |

### EPS Information

| | |
|---|---|
| Current Quarter EPS Consensus Estimate | 0.45 |
| Current Year EPS Consensus Estimate | 2.31 |
| Estimated Long-Term EPS Growth Rate | 4.60 |
| Next EPS Report Date | 04/24/2008 |

### Consensus Recommendations

| | |
|---|---|
| Current (1=Strong Buy, 5=Strong Sell) | 2.53 |
| 30 Days Ago | 2.57 |
| 60 Days Ago | 2.57 |
| 90 Days Ago | 2.72 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 15.50 | vs. Previous Year | 8.00% | vs. Previous Year | 5.96% |
| Trailing 12 Months: | 15.96 | vs. Previous Quarter | -72.73% | vs. Previous Quarter: | -30.88% |
| PEG Ratio | 3.37 | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 2.19 | 12/31/07 | 14.24 | 12/31/07 | 3.83 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Price/Cash Flow | 8.82 | 09/30/07 | | 14.26 | 09/30/07 | | 3.82 |
| Price / Sales | 1.77 | 06/30/07 | | 14.51 | 06/30/07 | | 3.87 |
| **Current Ratio** | | **Quick Ratio** | | | **Operating Margin** | | |
| 12/31/07 | - | 12/31/07 | | - | 12/31/07 | | 11.01 |
| 09/30/07 | 0.89 | 09/30/07 | | 0.65 | 09/30/07 | | 11.05 |
| 06/30/07 | 0.87 | 06/30/07 | | 0.60 | 06/30/07 | | 11.19 |
| **Net Margin** | | **Pre-Tax Margin** | | | **Book Value** | | |
| 12/31/07 | - | 12/31/07 | | - | 12/31/07 | | - |
| 09/30/07 | 17.18 | 09/30/07 | | 17.18 | 09/30/07 | | 16.32 |
| 06/30/07 | 17.08 | 06/30/07 | | 17.08 | 06/30/07 | | 15.68 |
| **Inventory Turnover** | | **Debt-to-Equity** | | | **Debt to Captial** | | |
| 12/31/07 | - | 12/31/07 | | - | 12/31/07 | | - |
| 09/30/07 | 5.42 | 09/30/07 | | 1.12 | 09/30/07 | | 51.31 |
| 06/30/07 | 5.45 | 06/30/07 | | 1.19 | 06/30/07 | | 52.90 |

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## TECO ENERGY INC (NYSE)

Scottrade

| TE | 16.20 | ▼-0.02 | (-0.12%) | Vol. 713,000 | 13:03 ET |
|---|---|---|---|---|---|

TECO Energy, Inc. is a diversified, energy-related holding company. Its principal businesses are Tampa Electric, Peoples Gas, Florida's largest natural gas distributor; TECO Power Services, an independent power company; TECO Transport, a river and ocean transportation company; TECO Coal, producer of coal and synthetic fuel; and TECO Solutions, an energy services/engineering company. (Company Press Release)

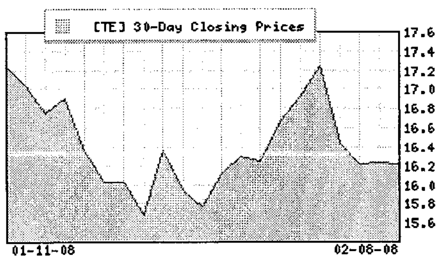
### General Information

TECO ENERGY
702 N. Franklin Street
Tampa, FL 33602
Phone: 813-228-1111
Fax: 813-228-1670
Web: www.tecoenergy.com
Email: investorrelations@tecoenergy.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 05/06/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 16.22 |
| 52 Week High | 18.58 |
| 52 Week Low | 14.84 |
| Beta | 0.68 |
| 20 Day Moving Average | 1,986,913.38 |
| Target Price Consensus | 17.72 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -5.92 | 4 Week | -0.99 |
| 12 Week | -5.15 | 12 Week | 3.93 |
| YTD | -5.75 | YTD | 3.95 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 210.68 | Dividend Yield | 4.81% |
| | | Annual Dividend | $0.78 |
| Market Capitalization (millions) | 3,417.20 | Payout Ratio | 0.75 |
| Short Ratio | 6.43 | Change in Payout Ratio | -0.01 |
| Last Split Date | 08/31/1993 | Last Dividend Payout / Amount | 11/13/2007 / $0.19 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.22 | Current (1=Strong Buy, 5=Strong Sell) | 3.00 |
| Current Year EPS Consensus Estimate | 1.05 | 30 Days Ago | 2.71 |
| Estimated Long-Term EPS Growth Rate | 7.30 | 60 Days Ago | 2.71 |
| Next EPS Report Date | 05/06/2008 | 90 Days Ago | 2.71 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 15.49 | vs. Previous Year | 11.11% | vs. Previous Year | 3.89% |
| Trailing 12 Months: | 15.60 | vs. Previous Quarter | -47.37% | vs. Previous Quarter: | -13.30% |
| PEG Ratio | 2.11 | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 1.83 | 12/31/07 | 12.01 | 12/31/07 | 3.01 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 6.85 | 09/30/07 | 11.86 | 09/30/07 | 2.93 |
| Price / Sales | 0.97 | 06/30/07 | 12.07 | 06/30/07 | 2.88 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 6.17 |
| 09/30/07 | 1.35 | 09/30/07 | 1.11 | 09/30/07 | 6.08 |
| 06/30/07 | 1.24 | 06/30/07 | 0.99 | 06/30/07 | 6.15 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 9.04 | 09/30/07 | 9.04 | 09/30/07 | 8.88 |
| 06/30/07 | 9.12 | 06/30/07 | 9.12 | 06/30/07 | 8.67 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 15.82 | 09/30/07 | 1.85 | 09/30/07 | 64.89 |
| 06/30/07 | 14.95 | 06/30/07 | 1.90 | 06/30/07 | 65.57 |

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**Zacks.com Quotes and Research**

| **UIL HLDG CORP** (NYSE) | | | | Scottrade | |
|---|---|---|---|---|---|
| UIL | 34.16 | ▼-0.82 | (-2.34%) | Vol. 112,100 | 14:50 ET |

UIL Holdings Corporation is the holding company for The United Illuminating Company and United Resources. United Illuminating Company is aNew Haven-based regional distribution utility that provides electricity and energy-related services to customers in municipalities in the Greater New Haven and Greater Bridgeport areas.(PR)

## General Information

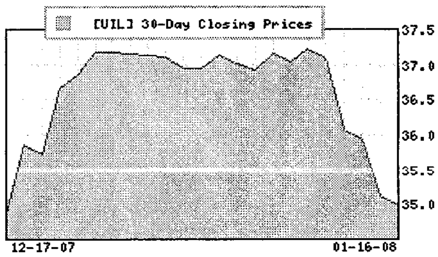
UIL HOLDINGS CP
157 Church Street
New Haven, CT 06506
Phone: 203 499-2000
Fax: 203 499-2414
Web: www.uil.com
Email: Susan.Allen@uinet.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 02/19/2008 |

## Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 34.98 |
| 52 Week High | 41.24 |
| 52 Week Low | 27.02 |
| Beta | 1.06 |
| 20 Day Moving Average | 136,190.50 |
| Target Price Consensus | 36.38 |




| **% Price Change** | | **% Price Change Relative to S&P 500** | |
|---|---|---|---|
| 4 Week | -2.07 | 4 Week | 3.62 |
| 12 Week | 6.16 | 12 Week | 17.19 |
| YTD | -5.33 | YTD | 2.31 |

| **Share Information** | | **Dividend Information** | |
|---|---|---|---|
| Shares Outstanding (millions) | 25.16 | Dividend Yield | 4.94% |
| | | Annual Dividend | $1.73 |
| Market Capitalization (millions) | 880.10 | Payout Ratio | 0.00 |
| Short Ratio | 11.49 | Change in Payout Ratio | 0.00 |
| Last Split Date | 07/05/2006 | Last Dividend Payout / Amount | 12/03/2007 / $0.43 |

| **EPS Information** | | **Consensus Recommendations** | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.23 | Current (1=Strong Buy, 5=Strong Sell) | 2.33 |
| Current Year EPS Consensus Estimate | 1.74 | 30 Days Ago | 2.33 |
| Estimated Long-Term EPS Growth Rate | - | 60 Days Ago | 2.33 |
| Next EPS Report Date | 02/19/2008 | 90 Days Ago | 2.33 |

## Fundamental Ratios

| **P/E** | | **EPS Growth** | | **Sales Growth** | |
|---|---|---|---|---|---|
| Current FY Estimate: | 17.32 | vs. Previous Year | 19.74% | vs. Previous Year | 2.58% |
| Trailing 12 Months: | 22.00 | vs. Previous Quarter | 139.47% | vs. Previous Quarter: | 23.60% |
| PEG Ratio | - | | | | |
| **Price Ratios** | | **ROE** | | **ROA** | |
| Price/Book | 1.90 | 09/30/07 | - | 09/30/07 | - |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 6.21 | 06/30/07 | 8.69 | 06/30/07 | 2.37 |
| Price / Sales | - | 03/31/07 | 7.67 | 03/31/07 | 2.16 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 1.18 | 06/30/07 | 1.16 | 06/30/07 | 4.70 |
| 03/31/07 | 1.02 | 03/31/07 | 1.01 | 03/31/07 | 4.26 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 18.20 | 06/30/07 | 18.20 | 06/30/07 | 18.45 |
| 03/31/07 | 18.31 | 03/31/07 | 18.31 | 03/31/07 | 18.01 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 09/30/07 | - | 09/30/07 | - | 09/30/07 | - |
| 06/30/07 | 181.28 | 06/30/07 | 1.09 | 06/30/07 | 52.07 |
| 03/31/07 | 205.45 | 03/31/07 | 0.89 | 03/31/07 | 47.16 |

ZACKS INVESTMENT RESEARCH
*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## VECTREN CORP (NYSE)

Scottrade

| | | | | | |
|---|---|---|---|---|---|
| VVC | 27.93 | ▾-0.11 | (-0.39%) | Vol. 141,200 | 13:08 ET |

Vectren Corp., through its regulated subsidiaries Indiana Gas and SIGECO, offers gas and/or electricity to customers in adjoining service areas that cover nearly two-thirds of Indiana. Vectren's non-regulated subsidiaries currently offer energy-related products and services, including energy marketing, fiber-optic based communication services, and utility related services including materials management, debt collections, locating, meter reading and trenching services to customers throughout the surrounding region. (PRESS RELEASE)

### General Information

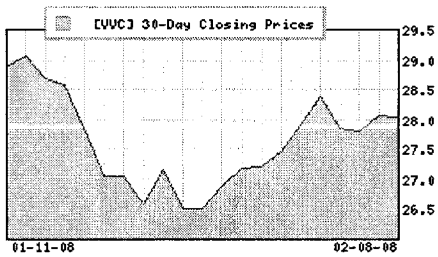
VECTREN CORP
One Vectren Square
Evansville, IN 47708
Phone: 812 491-4000
Fax: -
Web: www.vectren.com
Email: sschein@vectren.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 04/22/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 28.04 |
| 52 Week High | 30.50 |
| 52 Week Low | 24.85 |
| Beta | 0.53 |
| 20 Day Moving Average | 432,051.19 |
| Target Price Consensus | 32.33 |




**% Price Change**

| | |
|---|---|
| 4 Week | -2.91 |
| 12 Week | -2.47 |
| YTD | -3.34 |

**% Price Change Relative to S&P 500**

| | |
|---|---|
| 4 Week | 2.18 |
| 12 Week | 6.87 |
| YTD | 6.61 |

**Share Information**

| | |
|---|---|
| Shares Outstanding (millions) | 76.52 |
| Market Capitalization (millions) | 2,145.54 |
| Short Ratio | 26.68 |
| Last Split Date | 10/05/1998 |

**Dividend Information**

| | |
|---|---|
| Dividend Yield | 4.64% |
| Annual Dividend | $1.30 |
| Payout Ratio | 0.70 |
| Change in Payout Ratio | -0.02 |
| Last Dividend Payout / Amount | 11/13/2007 / $0.32 |

### EPS Information

| | |
|---|---|
| Current Quarter EPS Consensus Estimate | 0.92 |
| Current Year EPS Consensus Estimate | 1.95 |
| Estimated Long-Term EPS Growth Rate | 4.70 |
| Next EPS Report Date | 04/22/2008 |

### Consensus Recommendations

| | |
|---|---|
| Current (1=Strong Buy, 5=Strong Sell) | 1.88 |
| 30 Days Ago | 1.83 |
| 60 Days Ago | 1.83 |
| 90 Days Ago | 1.83 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.35 | vs. Previous Year | 7.27% | vs. Previous Year | 5.86% |
| Trailing 12 Months: | 15.07 | vs. Previous Quarter | 227.78% | vs. Previous Quarter: | 69.06% |
| PEG Ratio | 3.07 | | | | |

**Price Ratios** **ROE** **ROA**

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.77 | 12/31/07 | 11.65 | 12/31/07 | 3.57 |
| Price/Cash Flow | 7.44 | 09/30/07 | 11.46 | 09/30/07 | 3.46 |
| Price / Sales | 0.94 | 06/30/07 | 11.46 | 06/30/07 | 3.46 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 6.22 |
| 09/30/07 | 0.61 | 09/30/07 | 0.39 | 09/30/07 | 6.16 |
| 06/30/07 | 0.60 | 06/30/07 | 0.43 | 06/30/07 | 6.18 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 8.84 | 09/30/07 | 8.84 | 09/30/07 | 15.85 |
| 06/30/07 | 8.09 | 06/30/07 | 8.09 | 06/30/07 | 15.94 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 9.17 | 09/30/07 | 1.00 | 09/30/07 | 49.92 |
| 06/30/07 | 9.30 | 06/30/07 | 0.99 | 06/30/07 | 49.79 |

ZACKS INVESTMENT RESEARCH

*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## XCEL ENERGY INC (NYSE)

Scottrade

| XEL | 20.58 | ▼-0.03 | (-0.15%) | Vol. 1,184,829 | 13:10 ET |
|---|---|---|---|---|---|

Xcel Energy Inc. is predominantly an operating public utility engaged in the generation, transmission and distribution of electricity and the transportation, storage and distribution of natural gas. The company has two significant subsidiaries, Northern States Power Company, a Wisconsin corporation, and NRG Energy, Inc.

### General Information

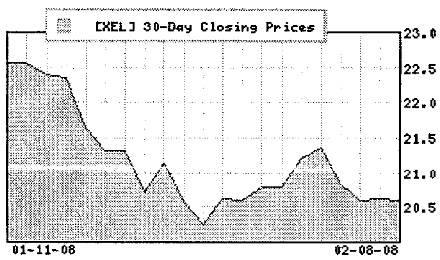
XCEL ENERGY INC
414 Nicollet Mall
Minneapolis, MN 55401
Phone: 612 330-5500
Fax: 612 330-2900
Web: www.xcelenergy.com
Email: Paul.A.Johnson@xcelenergy.com

| | |
|---|---|
| Industry | UTIL-ELEC PWR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 12/31/07 |
| Next EPS Date | 04/23/2008 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 20.61 |
| 52 Week High | 25.03 |
| 52 Week Low | 19.59 |
| Beta | 0.72 |
| 20 Day Moving Average | 2,947,012.50 |
| Target Price Consensus | 23.67 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -8.64 | 4 Week | -3.86 |
| 12 Week | -6.95 | 12 Week | 1.96 |
| YTD | -8.68 | YTD | 0.72 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 419.93 | Dividend Yield | 4.46% |
| | | Annual Dividend | $0.92 |
| Market Capitalization (millions) | 8,654.76 | Payout Ratio | 0.63 |
| Short Ratio | 11.51 | Change in Payout Ratio | -0.03 |
| Last Split Date | 06/02/1998 | Last Dividend Payout / Amount | 12/24/2007 / $0.23 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.29 | Current (1=Strong Buy, 5=Strong Sell) | 2.50 |
| Current Year EPS Consensus Estimate | 1.51 | 30 Days Ago | 2.43 |
| Estimated Long-Term EPS Growth Rate | 5.20 | 60 Days Ago | 2.43 |
| Next EPS Report Date | 04/23/2008 | 90 Days Ago | 2.43 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.65 | vs. Previous Year | 36.36% | vs. Previous Year | 5.53% |
| Trailing 12 Months: | 14.02 | vs. Previous Quarter | -46.43% | vs. Previous Quarter: | 8.47% |
| PEG Ratio | 2.62 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.40 | 12/31/07 | 10.59 | 12/31/07 | 2.84 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 5.69 | 09/30/07 | 10.10 | 09/30/07 | 2.70 |
| Price / Sales | 0.86 | 06/30/07 | 9.93 | 06/30/07 | 2.65 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | 6.34 |
| 09/30/07 | 1.07 | 09/30/07 | 0.84 | 09/30/07 | 6.08 |
| 06/30/07 | 0.87 | 06/30/07 | 0.72 | 06/30/07 | 5.85 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 8.65 | 09/30/07 | 8.65 | 09/30/07 | 14.68 |
| 06/30/07 | 7.88 | 06/30/07 | 7.88 | 06/30/07 | 14.66 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Captial** | |
| 12/31/07 | - | 12/31/07 | - | 12/31/07 | - |
| 09/30/07 | 10.20 | 09/30/07 | 1.18 | 09/30/07 | 53.65 |
| 06/30/07 | 10.02 | 06/30/07 | 1.10 | 06/30/07 | 52.03 |

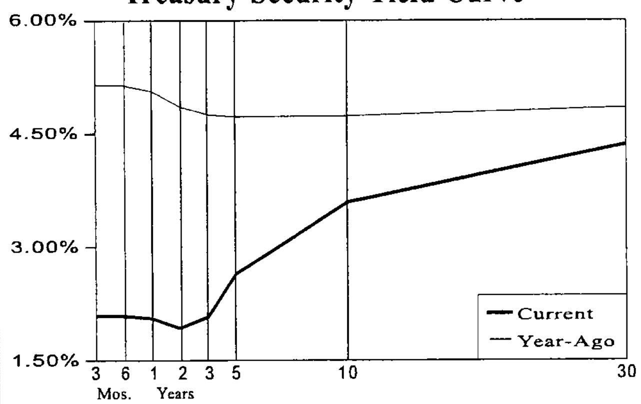
# ATTACHMENT C

# Selected Yields

| | Recent (2/06/08) | 3 Months Ago (11/07/07) | Year Ago (2/07/07) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 3.50 | 5.00 | 6.25 |
| Federal Funds | 3.00 | 4.50 | 5.25 |
| Prime Rate | 6.00 | 7.50 | 8.25 |
| 30-day CP (A1/P1) | 3.04 | 4.53 | 5.24 |
| 3-month LIBOR | 3.13 | 4.90 | 5.36 |
| **Bank CDs** | | | |
| 6-month | 2.30 | 2.83 | 3.27 |
| 1-year | 2.39 | 3.55 | 3.86 |
| 5-year | 2.86 | 3.90 | 3.91 |
| **U.S. Treasury Securities** | | | |
| 3-month | 2.09 | 3.44 | 5.15 |
| 6-month | 2.09 | 3.73 | 5.15 |
| 1-year | 2.06 | 3.83 | 5.07 |
| 5-year | 2.65 | 3.88 | 4.73 |
| 10-year | 3.59 | 4.31 | 4.74 |
| 10-year (inflation-protected) | 1.26 | 1.91 | 2.38 |
| 30-year | 4.36 | 4.65 | 4.85 |
| 30-year Zero | 4.40 | 4.66 | 4.80 |

| | Recent (2/06/08) | 3 Months Ago (11/07/07) | Year Ago (2/07/07) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 4.31 | 5.53 | 5.72 |
| FHLMC 6.5% (Gold) | 4.68 | 5.75 | 5.82 |
| FNMA 6.5% | 4.21 | 5.58 | 5.76 |
| FNMA ARM | 5.19 | 5.90 | 5.62 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.54 | 5.81 | 5.56 |
| Industrial (25/30-year) A | 6.12 | 5.89 | 5.79 |
| Utility (25/30-year) A | 6.02 | 6.07 | 5.81 |
| Utility (25/30-year) Baa/BBB | 6.20 | 6.15 | 6.07 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.79 | 4.28 | 4.11 |
| Germany | 3.90 | 4.15 | 4.03 |
| Japan | 1.43 | 1.57 | 1.74 |
| United Kingdom | 4.46 | 4.83 | 4.96 |
| **Preferred Stocks** | | | |
| Utility A | 6.09 | 6.38 | 6.14 |
| Financial A | 6.95 | 7.84 | 6.44 |
| Financial Adjustable A | 5.51 | 5.51 | 5.51 |

### Treasury Security Yield Curve




| | Recent (2/06/08) | 3 Months Ago (11/07/07) | Year Ago (2/07/07) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.39 | 4.40 | 4.31 |
| 25-Bond Index (Revs) | 4.76 | 4.73 | 4.59 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 1.65 | 3.30 | 3.60 |
| 1-year A | 1.75 | 3.34 | 3.70 |
| 5-year Aaa | 2.66 | 3.46 | 3.62 |
| 5-year A | 2.96 | 3.76 | 3.90 |
| 10-year Aaa | 3.34 | 3.84 | 3.76 |
| 10-year A | 3.63 | 4.14 | 4.17 |
| 25/30-year Aaa | 4.26 | 4.52 | 4.10 |
| 25/30-year A | 4.39 | 4.67 | 4.42 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.40 | 4.72 | 4.48 |
| Electric AA | 4.40 | 4.72 | 4.41 |
| Housing AA | 4.70 | 4.95 | 4.65 |
| Hospital AA | 4.80 | 4.90 | 4.65 |
| Toll Road Aaa | 4.45 | 4.72 | 4.52 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | **1/30/08** | **1/16/08** | **Change** | **12 Wks.** | **26 Wks.** | **52 Wks.** |
| Excess Reserves | 1460 | 1710 | -250 | 1701 | 2145 | 1861 |
| Borrowed Reserves | 390 | 1377 | -987 | 1699 | 1291 | 729 |
| Net Free/Borrowed Reserves | 1070 | 333 | 737 | 2 | 854 | 1133 |

**MONEY SUPPLY**

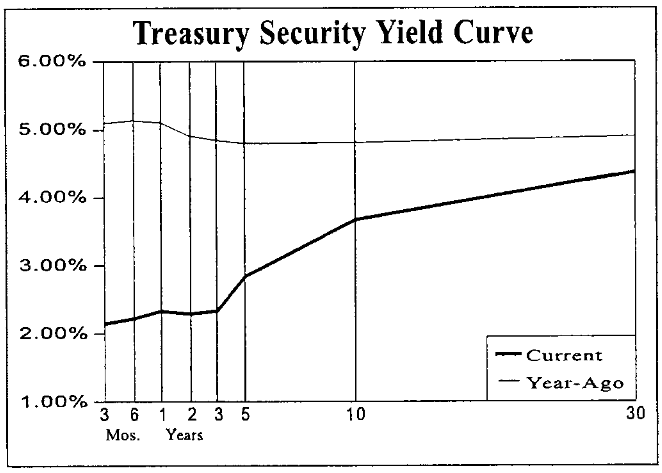
*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | **1/21/08** | **1/14/08** | **Change** | **3 Mos.** | **6 Mos.** | **12 Mos.** |
| M1 (Currency+demand deposits) | 1372.3 | 1345.8 | 26.5 | 1.2% | 0.6% | -0.0% |
| M2 (M1+savings+small time deposits) | 7491.7 | 7441.3 | 50.4 | 6.6% | 5.9% | 5.7% |

# Selected Yields

| | Recent (1/30/08) | 3 Months Ago (10/31/07) | Year Ago (1/31/07) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 3.50 | 5.00 | 6.25 |
| Federal Funds | 3.00 | 4.50 | 5.25 |
| Prime Rate | 6.00 | 7.50 | 8.25 |
| 30-day CP (A1/P1) | 3.06 | 4.53 | 5.24 |
| 3-month LIBOR | 3.24 | 4.89 | 5.36 |
| **Bank CDs** | | | |
| 6-month | 2.50 | 2.89 | 3.30 |
| 1-year | 2.60 | 3.57 | 3.86 |
| 5-year | 3.01 | 3.90 | 3.91 |
| **U.S. Treasury Securities** | | | |
| 3-month | 2.15 | 3.91 | 5.10 |
| 6-month | 2.22 | 4.07 | 5.14 |
| 1-year | 2.33 | 3.98 | 5.11 |
| 5-year | 2.84 | 4.17 | 4.80 |
| 10-year | 3.67 | 4.47 | 4.81 |
| 10-year (inflation-protected) | 1.25 | 2.13 | 2.38 |
| 30-year | 4.38 | 4.75 | 4.91 |
| 30-year Zero | 4.46 | 4.74 | 4.86 |

| | Recent (1/30/08) | 3 Months Ago (10/31/07) | Year Ago (1/31/07) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 4.38 | 5.65 | 5.79 |
| FHLMC 6.5% (Gold) | 4.65 | 5.79 | 5.91 |
| FNMA 6.5% | 4.28 | 5.64 | 5.84 |
| FNMA ARM | 5.30 | 5.91 | 5.63 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.60 | 5.88 | 5.63 |
| Industrial (25/30-year) A | 6.15 | 5.96 | 5.84 |
| Utility (25/30-year) A | 6.06 | 6.13 | 5.88 |
| Utility (25/30-year) Baa/BBB | 6.15 | 6.22 | 6.14 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.90 | 4.31 | 4.18 |
| Germany | 4.02 | 4.24 | 4.10 |
| Japan | 1.44 | 1.61 | 1.70 |
| United Kingdom | 4.57 | 4.93 | 4.98 |
| **Preferred Stocks** | | | |
| Utility A | 6.01 | 6.22 | 6.10 |
| Financial A | 7.08 | 6.95 | 6.43 |
| Financial Adjustable A | 5.55 | 5.50 | 5.50 |




| | Recent (1/30/08) | 3 Months Ago (10/31/07) | Year Ago (1/31/07) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.29 | 4.33 | 4.32 |
| 25-Bond Index (Revs) | 4.71 | 4.67 | 4.59 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 2.06 | 3.32 | 3.61 |
| 1-year A | 2.52 | 3.42 | 3.71 |
| 5-year Aaa | 2.73 | 3.47 | 3.69 |
| 5-year A | 2.98 | 3.77 | 3.88 |
| 10-year Aaa | 3.34 | 3.81 | 3.86 |
| 10-year A | 3.72 | 4.11 | 4.28 |
| 25/30-year Aaa | 4.27 | 4.40 | 4.17 |
| 25/30-year A | 4.48 | 4.58 | 4.50 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.60 | 4.55 | 4.60 |
| Electric AA | 4.60 | 4.65 | 4.57 |
| Housing AA | 4.70 | 4.80 | 4.66 |
| Hospital AA | 4.75 | 4.80 | 4.68 |
| Toll Road Aaa | 4.55 | 4.65 | 4.58 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | **1/16/08** | **1/2/08** | **Change** | **12 Wks.** | **26 Wks.** | **52 Wks.** |
| Excess Reserves | 1713 | 2393 | -680 | 1606 | 2160 | 1867 |
| Borrowed Reserves | 1377 | 5308 | -3931 | 1682 | 1284 | 720 |
| Net Free/Borrowed Reserves | 336 | -2915 | 3251 | -76 | 876 | 1147 |

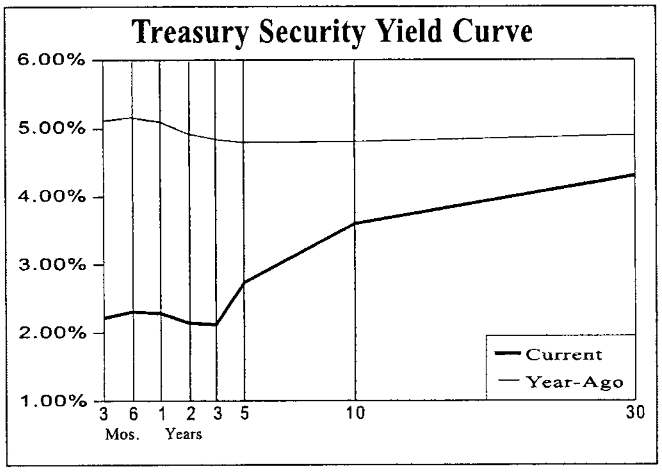
**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | **1/14/08** | **1/7/08** | **Change** | **3 Mos.** | **6 Mos.** | **12 Mos.** |
| M1 (Currency+demand deposits) | 1345.7 | 1361.8 | -16.1 | -7.6% | -3.7% | -2.5% |
| M2 (M1+savings+small time deposits) | 7440.8 | 7457.7 | -16.9 | 4.3% | 4.8% | 5.0% |

# Selected Yields

| | Recent (1/23/08) | 3 Months Ago (10/24/07) | Year Ago (1/24/07) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 4.00 | 5.25 | 6.25 |
| Federal Funds | 3.50 | 4.75 | 5.25 |
| Prime Rate | 6.50 | 7.75 | 8.25 |
| 30-day CP (A1/P1) | 3.12 | 4.72 | 5.25 |
| 3-month LIBOR | 3.33 | 5.07 | 5.36 |
| **Bank CDs** | | | |
| 6-month | 2.64 | 2.89 | 3.30 |
| 1-year | 2.96 | 3.62 | 3.86 |
| 5-year | 3.35 | 3.91 | 3.91 |
| **U.S. Treasury Securities** | | | |
| 3-month | 2.22 | 3.87 | 5.12 |
| 6-month | 2.31 | 4.00 | 5.16 |
| 1-year | 2.29 | 4.01 | 5.10 |
| 5-year | 2.74 | 3.99 | 4.80 |
| 10-year | 3.60 | 4.34 | 4.81 |
| 10-year (inflation-protected) | 1.32 | 2.05 | 2.41 |
| 30-year | 4.31 | 4.64 | 4.91 |
| 30-year Zero | 4.39 | 4.66 | 4.86 |


Treasury Security Yield Curve


| | Recent (1/23/08) | 3 Months Ago (10/24/07) | Year Ago (1/24/07) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 4.57 | 5.56 | 5.75 |
| FHLMC 6.5% (Gold) | 4.97 | 5.76 | 5.83 |
| FNMA 6.5% | 4.61 | 5.61 | 5.76 |
| FNMA ARM | 5.28 | 5.88 | 5.58 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.86 | 5.68 | 5.62 |
| Industrial (25/30-year) A | 6.05 | 5.86 | 5.83 |
| Utility (25/30-year) A | 6.13 | 6.03 | 5.87 |
| Utility (25/30-year) Baa/BBB | 6.20 | 6.09 | 6.14 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.88 | 4.29 | 4.17 |
| Germany | 3.89 | 4.15 | 4.04 |
| Japan | 1.36 | 1.58 | 1.67 |
| United Kingdom | 4.42 | 4.84 | 4.91 |
| **Preferred Stocks** | | | |
| Utility A | 6.03 | 6.23 | 6.12 |
| Financial A | 7.35 | 6.91 | 6.47 |
| Financial Adjustable A | 5.50 | 5.50 | 5.50 |
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.15 | 4.39 | 4.25 |
| 25-Bond Index (Revs) | 4.63 | 4.73 | 4.55 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 2.10 | 3.35 | 3.57 |
| 1-year A | 2.20 | 3.45 | 3.67 |
| 5-year Aaa | 2.60 | 3.42 | 3.64 |
| 5-year A | 2.70 | 3.72 | 3.92 |
| 10-year Aaa | 3.17 | 3.71 | 3.80 |
| 10-year A | 3.37 | 4.01 | 4.20 |
| 25/30-year Aaa | 4.11 | 4.27 | 4.13 |
| 25/30-year A | 4.31 | 4.45 | 4.45 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.40 | 4.50 | 4.50 |
| Electric AA | 4.45 | 4.50 | 4.43 |
| Housing AA | 4.55 | 4.65 | 4.60 |
| Hospital AA | 4.60 | 4.60 | 4.60 |
| Toll Road Aaa | 4.45 | 4.50 | 4.49 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | 1/16/08 | 1/2/08 | Change | 12 Wks. | 26 Wks. | 52 Wks. |
| Excess Reserves | 1712 | 2382 | -670 | 1604 | 2160 | 1867 |
| Borrowed Reserves | 1377 | 5308 | -3931 | 1682 | 1284 | 720 |
| Net Free/Borrowed Reserves | 335 | -2926 | 3261 | -78 | 875 | 1147 |

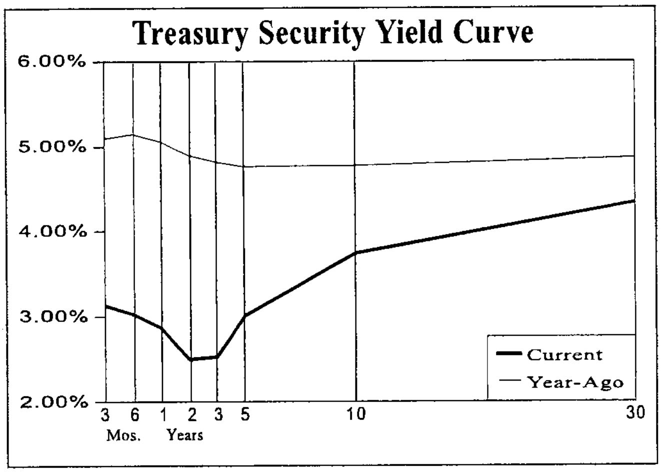
**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | 1/7/08 | 12/31/07 | Change | 3 Mos. | 6 Mos. | 12 Mos. |
| M1 (Currency+demand deposits) | 1363.0 | 1363.2 | -0.2 | -0.8% | -0.6% | 0.0% |
| M2 (M1+savings+small time deposits) | 7455.6 | 7461.5 | -5.9 | 5.1% | 5.7% | 5.5% |

# Selected Yields

| | Recent (1/16/08) | 3 Months Ago (10/17/07) | Year Ago (1/17/07) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 4.75 | 5.25 | 6.25 |
| Federal Funds | 4.25 | 4.75 | 5.25 |
| Prime Rate | 7.25 | 7.75 | 8.25 |
| 30-day CP (A1/P1) | 3.99 | 4.86 | 5.24 |
| 3-month LIBOR | 3.95 | 5.20 | 5.36 |
| **Bank CDs** | | | |
| 6-month | 2.80 | 2.90 | 3.30 |
| 1-year | 3.22 | 3.61 | 3.85 |
| 5-year | 3.58 | 3.91 | 3.91 |
| **U.S. Treasury Securities** | | | |
| 3-month | 3.13 | 3.99 | 5.10 |
| 6-month | 3.03 | 4.16 | 5.15 |
| 1-year | 2.87 | 4.26 | 5.06 |
| 5-year | 3.01 | 4.21 | 4.77 |
| 10-year | 3.74 | 4.55 | 4.78 |
| 10-year (inflation-protected) | 1.45 | 2.25 | 2.48 |
| 30-year | 4.34 | 4.83 | 4.87 |
| 30-year Zero | 4.42 | 4.82 | 4.82 |




| | Recent (1/16/08) | 3 Months Ago (10/17/07) | Year Ago (1/17/07) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 4.69 | 5.70 | 5.68 |
| FHLMC 6.5% (Gold) | 5.10 | 5.85 | 5.81 |
| FNMA 6.5% | 4.75 | 5.80 | 5.75 |
| FNMA ARM | 5.34 | 5.89 | 5.58 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.79 | 5.93 | 5.62 |
| Industrial (25/30-year) A | 6.03 | 6.01 | 5.83 |
| Utility (25/30-year) A | 6.07 | 6.21 | 5.86 |
| Utility (25/30-year) Baa/BBB | 6.22 | 6.27 | 6.14 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.82 | 4.43 | 4.16 |
| Germany | 3.98 | 4.39 | 4.04 |
| Japan | 1.39 | 1.66 | 1.69 |
| United Kingdom | 4.38 | 5.03 | 4.90 |
| **Preferred Stocks** | | | |
| Utility A | 5.96 | 6.23 | 6.01 |
| Financial A | 7.39 | 6.85 | 6.42 |
| Financial Adjustable A | 5.49 | 5.49 | 5.49 |
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.21 | 4.48 | 4.21 |
| 25-Bond Index (Revs) | 4.66 | 4.78 | 4.55 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 2.60 | 3.36 | 3.57 |
| 1-year A | 2.65 | 3.46 | 3.67 |
| 5-year Aaa | 2.88 | 3.50 | 3.63 |
| 5-year A | 3.18 | 3.80 | 3.82 |
| 10-year Aaa | 3.36 | 3.80 | 3.79 |
| 10-year A | 3.65 | 4.10 | 4.21 |
| 25/30-year Aaa | 4.12 | 4.37 | 4.14 |
| 25/30-year A | 4.25 | 4.55 | 4.47 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.25 | 4.50 | 4.58 |
| Electric AA | 4.25 | 4.60 | 4.54 |
| Housing AA | 4.50 | 4.75 | 4.63 |
| Hospital AA | 4.55 | 4.70 | 4.65 |
| Toll Road Aaa | 4.30 | 4.60 | 4.53 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | **1/2/08** | **12/19/07** | **Change** | **12 Wks.** | **26 Wks.** | **52 Wks.** |
| Excess Reserves | 2393 | 1169 | 1224 | 1667 | 2189 | 1885 |
| Borrowed Reserves | 5308 | 3833 | 1475 | 1518 | 1199 | 676 |
| Net Free/Borrowed Reserves | -2915 | -2664 | -251 | 150 | 990 | 1209 |

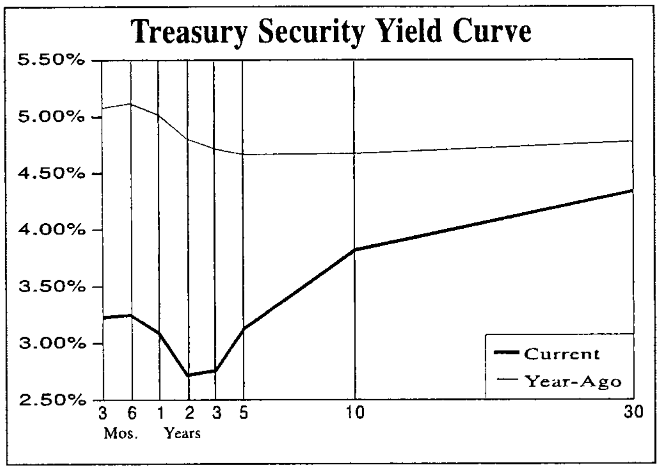
**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | **12/31/07** | **12/24/07** | **Change** | **3 Mos.** | **6 Mos.** | **12 Mos.** |
| M1 (Currency+demand deposits) | 1364.3 | 1355.2 | 9.1 | 2.4% | -0.5% | 0.5% |
| M2 (M1+savings+small time deposits) | 7471.9 | 7467.6 | 4.3 | 4.8% | 5.6% | 5.7% |

# Selected Yields

| | Recent (1/09/08) | 3 Months Ago (10/10/07) | Year Ago (1/10/07) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 4.75 | 5.25 | 6.25 |
| Federal Funds | 4.25 | 4.75 | 5.25 |
| Prime Rate | 7.25 | 7.75 | 8.25 |
| 30-day CP (A1/P1) | 4.28 | 4.84 | 5.24 |
| 3-month LIBOR | 4.44 | 5.25 | 5.36 |
| **Bank CDs** | | | |
| 6-month | 2.77 | 2.90 | 3.30 |
| 1-year | 3.38 | 3.61 | 3.85 |
| 5-year | 3.73 | 3.92 | 3.91 |
| **U.S. Treasury Securities** | | | |
| 3-month | 3.23 | 4.04 | 5.08 |
| 6-month | 3.25 | 4.26 | 5.12 |
| 1-year | 3.09 | 4.23 | 5.02 |
| 5-year | 3.13 | 4.37 | 4.67 |
| 10-year | 3.82 | 4.65 | 4.68 |
| 10-year (inflation-protected) | 1.53 | 2.35 | 2.42 |
| 30-year | 4.34 | 4.87 | 4.78 |
| 30-year Zero | 4.39 | 4.85 | 4.72 |




| | Recent (1/09/08) | 3 Months Ago (10/10/07) | Year Ago (1/10/07) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 5.04 | 5.90 | 5.61 |
| FHLMC 6.5% (Gold) | 5.28 | 5.98 | 5.73 |
| FNMA 6.5% | 5.18 | 5.92 | 5.64 |
| FNMA ARM | 5.36 | 5.90 | 5.58 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.79 | 5.97 | 5.53 |
| Industrial (25/30-year) A | 5.98 | 6.06 | 5.74 |
| Utility (25/30-year) A | 5.99 | 6.27 | 5.76 |
| Utility (25/30-year) Baa/BBB | 6.17 | 6.34 | 6.06 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.87 | 4.45 | 4.08 |
| Germany | 4.09 | 4.35 | 4.02 |
| Japan | 1.48 | 1.74 | 1.76 |
| United Kingdom | 4.40 | 4.98 | 4.81 |
| **Preferred Stocks** | | | |
| Utility A | 6.00 | 6.23 | 6.03 |
| Financial A | 7.61 | 6.83 | 6.41 |
| Financial Adjustable A | 5.48 | 5.49 | 5.49 |
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.32 | 4.42 | 4.15 |
| 25-Bond Index (Revs) | 4.72 | 4.72 | 4.50 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 2.70 | 3.38 | 3.50 |
| 1-year A | 2.80 | 3.48 | 3.60 |
| 5-year Aaa | 2.97 | 3.53 | 3.54 |
| 5-year A | 3.07 | 3.83 | 3.82 |
| 10-year Aaa | 3.43 | 3.84 | 3.72 |
| 10-year A | 3.73 | 4.14 | 4.12 |
| 25/30-year Aaa | 4.14 | 4.43 | 4.06 |
| 25/30-year A | 4.34 | 4.61 | 4.38 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.45 | 4.55 | 4.41 |
| Electric AA | 4.50 | 4.65 | 4.39 |
| Housing AA | 4.60 | 4.80 | 4.50 |
| Hospital AA | 4.65 | 4.78 | 4.53 |
| Toll Road Aaa | 4.50 | 4.65 | 4.47 |

# Federal Reserve Data

**BANK RESERVES**
*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

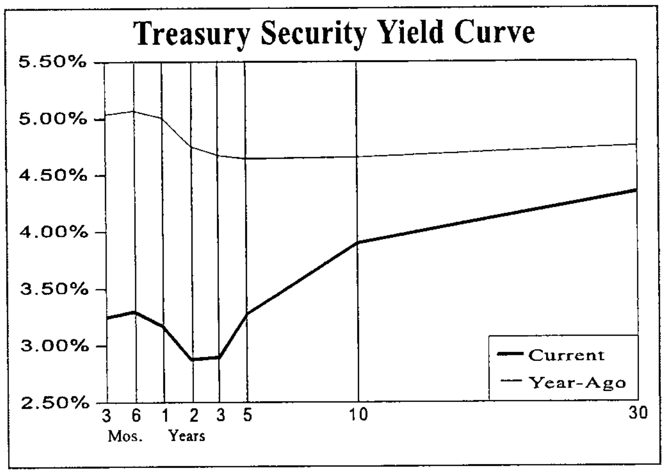
| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | 1/2/08 | 12/19/07 | Change | 12 Wks. | 26 Wks. | 52 Wks. |
| Excess Reserves | 2392 | 1174 | 1218 | 1668 | 2189 | 1886 |
| Borrowed Reserves | 35307 | 3833 | 31474 | 5803 | 3342 | 1787 |
| Net Free/Borrowed Reserves | -32915 | -2659 | -30256 | -4135 | -1153 | 98 |

**MONEY SUPPLY**
*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | 12/24/07 | 12/17/07 | Change | 3 Mos. | 6 Mos. | 12 Mos. |
| M1 (Currency+demand deposits) | 1355.1 | 1361.0 | -5.9 | 1.5% | 0.7% | -1.4% |
| M2 (M1+savings+small time deposits) | 7468.3 | 7460.2 | 8.1 | 4.8% | 5.6% | 5.9% |

# Selected Yields

| | Recent (1/02/08) | 3 Months Ago (10/03/07) | Year Ago (1/03/07) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 4.75 | 5.25 | 6.25 |
| Federal Funds | 4.25 | 4.75 | 5.25 |
| Prime Rate | 7.25 | 7.75 | 8.25 |
| 30-day CP (A1/P1) | 4.40 | 4.82 | 5.24 |
| 3-month LIBOR | 4.68 | 5.24 | 5.36 |
| **Bank CDs** | | | |
| 6-month | 2.81 | 2.91 | 3.30 |
| 1-year | 3.43 | 3.70 | 3.85 |
| 5-year | 3.73 | 3.92 | 3.91 |
| **U.S. Treasury Securities** | | | |
| 3-month | 3.25 | 3.94 | 5.04 |
| 6-month | 3.30 | 4.15 | 5.07 |
| 1-year | 3.17 | 4.10 | 5.01 |
| 5-year | 3.28 | 4.25 | 4.65 |
| 10-year | 3.90 | 4.56 | 4.66 |
| 10-year (inflation-protected) | 1.56 | 2.29 | 2.36 |
| 30-year | 4.35 | 4.80 | 4.76 |
| 30-year Zero | 4.38 | 4.80 | 4.71 |




| | Recent (1/02/08) | 3 Months Ago (10/03/07) | Year Ago (1/03/07) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 5.36 | 5.81 | 5.53 |
| FHLMC 6.5% (Gold) | 5.44 | 5.96 | 5.67 |
| FNMA 6.5% | 5.37 | 5.88 | 5.60 |
| FNMA ARM | 5.38 | 5.89 | 5.58 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.86 | 5.97 | 5.50 |
| Industrial (25/30-year) A | 5.92 | 6.02 | 5.73 |
| Utility (25/30-year) A | 5.94 | 6.22 | 5.79 |
| Utility (25/30-year) Baa/BBB | 6.11 | 6.31 | 6.06 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.91 | 4.36 | 4.05 |
| Germany | 4.21 | 4.33 | 3.95 |
| Japan | 1.51 | 1.69 | 1.69 |
| United Kingdom | 4.44 | 4.97 | 4.79 |
| **Preferred Stocks** | | | |
| Utility A | 6.31 | 6.32 | 6.07 |
| Financial A | 8.12 | 6.87 | 6.40 |
| Financial Adjustable A | 5.48 | 5.48 | 5.48 |
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.44 | 4.48 | 4.17 |
| 25-Bond Index (Revs) | 4.80 | 4.77 | 4.56 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 2.88 | 3.38 | 3.50 |
| 1-year A | 2.92 | 3.48 | 3.60 |
| 5-year Aaa | 3.19 | 3.48 | 3.54 |
| 5-year A | 3.49 | 3.58 | 3.83 |
| 10-year Aaa | 3.61 | 3.76 | 3.72 |
| 10-year A | 3.90 | 4.26 | 4.14 |
| 25/30-year Aaa | 4.26 | 4.38 | 4.06 |
| 25/30-year A | 4.37 | 4.68 | 4.39 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.40 | 4.67 | 4.50 |
| Electric AA | 4.40 | 4.65 | 4.44 |
| Housing AA | 4.65 | 4.85 | 4.55 |
| Hospital AA | 4.65 | 4.83 | 4.58 |
| Toll Road Aaa | 4.50 | 4.68 | 4.42 |

# Federal Reserve Data

## BANK RESERVES

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | **12/19/07** | **12/5/07** | **Change** | **12 Wks.** | **26 Wks.** | **52 Wks.** |
| Excess Reserves | 1173 | 1848 | -675 | 1608 | 2125 | 1850 |
| Borrowed Reserves | 3833 | 199 | 3634 | 954 | 836 | 487 |
| Net Free/Borrowed Reserves | -2660 | 1649 | -4309 | 653 | 1290 | 1363 |

## MONEY SUPPLY

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | **12/17/07** | **12/10/07** | **Change** | **3 Mos.** | **6 Mos.** | **12 Mos.** |
| M1 (Currency+demand deposits) | 1361.2 | 1371.3 | -10.1 | -0.7% | 0.7% | -0.3% |
| M2 (M1+savings+small time deposits) | 7460.2 | 7456.6 | 3.6 | 4.6% | 5.6% | 6.2% |

# ATTACHMENT D

# UNISOURCE ENERGY NYSE-UNS

RECENT PRICE **29.41** | P/E RATIO **17.0** (Trailing: 20.4; Median: 16.0) | RELATIVE P/E RATIO **1.06** | DIV'D YLD **3.3%** | VALUE LINE

**TIMELINESS** 4 Raised 8/17/07
**SAFETY** 3 New 12/31/04
**TECHNICAL** 2 Raised 2/1/08
**BETA** .60 (1.00 = Market)

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 20.8 | 18.3 | 18.9 | 13.9 | 19.3 | 26.0 | 20.8 | 24.9 | 24.9 | 34.8 | 37.5 | 40.0 |
| Low: | 12.3 | 13.9 | 12.3 | 10.4 | 11.1 | 13.8 | 13.7 | 16.0 | 22.9 | 24.3 | 29.5 | 27.6 |

**Target Price Range** 2010 | 2011 | 2012

**2010-12 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 35 | (+20%) | 8% |
| Low | 25 | (-15%) | Nil |

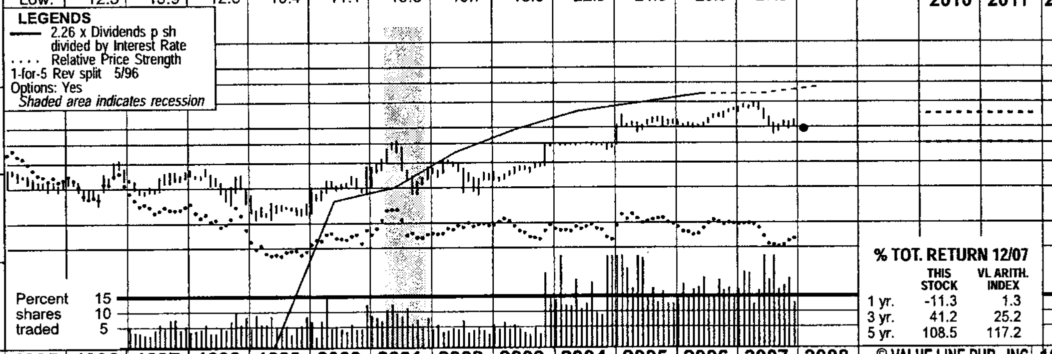
**Insider Decisions**

| | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 1 | 0 | 4 | 0 | 0 | 1 | 0 | 0 | 2 |
| to Sell | 1 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 1 |

**Institutional Decisions**

| | 1Q2007 | 2Q2007 | 3Q2007 |
|---|---|---|---|
| to Buy | 87 | 73 | 56 |
| to Sell | 67 | 81 | 87 |
| Hld's(000) | 31380 | 30634 | 31880 |

LEGENDS
— 2.26 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-5 Rev split 5/96
Options: Yes
Shaded area indicates recession




**% TOT. RETURN 12/07**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -11.3 | 1.3 |
| 3 yr. | 41.2 | 25.2 |
| 5 yr. | 108.5 | 117.2 |

| 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | © VALUE LINE PUB., INC. | 10-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 114.58 | 19.56 | 20.61 | 21.51 | 20.87 | 22.28 | 22.71 | 23.83 | 24.85 | 31.12 | 43.12 | 25.50 | 28.71 | 34.13 | 35.26 | 37.42 | 38.65 | 40.60 | Revenues per sh | 45.60 |
| d12.43 | d.30 | 2.06 | 3.44 | 4.58 | 6.82 | 5.29 | 3.48 | 3.96 | 4.23 | 5.41 | 4.80 | 5.20 | 5.29 | 5.21 | 5.68 | 5.40 | 5.70 | "Cash Flow" per sh | 6.35 |
| d28.05 | d12.40 | d.25 | .65 | 1.70 | 3.76 | 2.60 | .68 | 1.08 | 1.27 | 1.79 | .97 | 1.30 | 1.31 | 1.30 | 1.85 | 1.60 | 1.75 | Earnings per sh A | 1.90 |
| -- | -- | -- | -- | -- | -- | -- | -- | -- | .32 | .40 | .50 | .60 | .64 | .76 | .84 | .90 | .96 | Div'd Decl'd per sh B ■ † | 1.14 |
| 8.75 | 1.08 | 1.50 | 1.95 | 1.84 | 2.07 | 2.22 | 2.52 | 2.87 | 3.19 | 3.63 | 3.36 | 4.06 | 4.49 | 5.83 | 6.77 | 5.55 | 6.50 | Cap'l Spending per sh | 7.75 |
| d37.31 | d1.19 | d1.96 | d1.31 | .39 | 4.15 | 6.75 | 7.65 | 10.02 | 11.20 | 12.68 | 13.05 | 15.97 | 16.95 | 17.68 | 18.59 | 19.55 | 20.85 | Book Value per sh C | 22.25 |
| 5.14 | 32.09 | 32.14 | 32.14 | 32.13 | 32.13 | 32.14 | 32.26 | 32.35 | 33.22 | 33.50 | 33.58 | 33.79 | 34.26 | 34.87 | 35.19 | 35.70 | 36.20 | Common Shs Outst'g D | 37.70 |
| -- | -- | -- | 26.7 | 9.6 | 4.3 | 6.1 | 23.3 | 10.8 | 11.8 | 10.8 | 18.2 | 14.6 | 18.7 | 23.9 | 17.7 | 18.4 | | Avg Ann'l P/E Ratio | 16.0 |
| -- | -- | -- | 1.75 | .64 | .27 | .35 | 1.21 | .62 | .77 | .55 | .99 | .83 | .99 | 1.27 | .96 | .97 | | Relative P/E Ratio | 1.05 |
| -- | -- | -- | -- | -- | -- | -- | -- | -- | 2.1% | 2.1% | 2.8% | 3.2% | 2.6% | 2.5% | 2.6% | 3.1% | | Avg Ann'l Div'd Yield | 3.8% |
| | | | | | | 729.9 | 768.7 | 803.8 | 1033.7 | 1444.7 | 856.2 | 969.9 | 1169.0 | 1229.5 | 1316.9 | 1380 | 1470 | Revenues ($mill) | 1720 |
| | | | | | | 83.6 | 21.9 | 35.5 | 26.3 | 60.9 | 33.3 | 45.2 | 45.9 | 46.1 | 69.2 | 57.0 | 63.0 | Net Profit ($mill) | 71.0 |
| | | | | | | -- | 45.6% | 46.8% | 32.9% | 43.8% | 33.7% | 19.7% | 42.5% | 41.4% | 38.8% | 39.0% | 39.0% | Income Tax Rate | 39.0% |
| | | | | | | -- | -- | -- | -- | -- | -- | 2.2% | -- | 2.2% | 2.9% | 3.0% | 3.0% | AFUDC % to Net Profit | 3.0% |
| | | | | | | 90.7% | 89.4% | 86.1% | 84.2% | 79.6% | 81.5% | 79.2% | 77.1% | 75.3% | 72.9% | 68.5% | 67.0% | Long-Term Debt Ratio | 61.0% |
| | | | | | | 9.3% | 10.6% | 13.9% | 15.8% | 20.4% | 18.5% | 20.8% | 22.9% | 24.7% | 27.1% | 31.5% | 33.0% | Common Equity Ratio | 39.0% |
| | | | | | | 2322.3 | 2320.6 | 2340.5 | 2362.4 | 2081.3 | 2368.8 | 2589.0 | 2540.3 | 2494.9 | 2414.1 | 2230 | 2245 | Total Capital ($mill) | 2290 |
| | | | | | | 1935.5 | 1915.6 | 1729.9 | 1706.3 | 1677.7 | 1668.4 | 2069.2 | 2081.1 | 2171.5 | 2259.6 | 2320 | 2415 | Net Plant ($mill) | 2545 |
| | | | | | | 5.0% | 2.5% | 2.9% | 2.5% | 4.4% | 2.8% | 4.9% | 5.1% | 5.1% | 5.9% | 5.5% | 5.5% | Return on Total Cap'l | 6.0% |
| | | | | | | 38.5% | 8.9% | 11.0% | 7.1% | 14.3% | 7.6% | 8.4% | 7.9% | 7.5% | 10.6% | 8.0% | 8.5% | Return on Shr. Equity | 8.5% |
| | | | | | | 38.5% | 8.9% | 11.0% | 7.1% | 14.3% | 7.6% | 8.4% | 7.9% | 7.5% | 10.6% | 8.0% | 8.5% | Return on Com Equity E | 8.5% |
| | | | | | | 38.5% | 8.9% | 11.0% | 4.3% | 11.2% | 3.8% | 4.6% | 4.1% | 3.2% | 6.1% | 3.5% | 3.5% | Retained to Com Eq | 3.5% |
| | | | | | | -- | -- | -- | 39% | 22% | 51% | 45% | 48% | 57% | 43% | 56% | 55% | All Div'ds to Net Prof | 60% |

**CAPITAL STRUCTURE as of 9/30/07**
**Total Debt** $1607.2 mill. **Due in 5 Yrs** $1079.6 mill.
**LT Debt** $1532.3 mill. **LT Interest** $145.6 mill.
Incl. $528.9 mill. capitalized leases.

(LT interest earned: 1.6x)

**Pension Assets-12/06** $176 mill. **Oblig.** $218 mill.
**Pfd Stock** None

**Common Stock** 35,338,420 shs. **as of 10/31/07**
**MARKET CAP: $1.1 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.2 | +3.9 | +3.7 |
| Avg. Indust. Use (MWH) | 3293 | 3421 | 3431 |
| Avg. Indust. Revs. per KWH (¢) | 6.50 | 6.60 | 6.60 |
| Capacity at Peak (Mw) | 2275 | 2567 | 2696 |
| Peak Load, Summer (Mw) | 2458 | 2792 | 2913 |
| Annual Load Factor (%) | 64.6 | 63.9 | 64.0 |
| % Change Customers (yr-end) | +2.1 | +2.6 | +1.8 |
| Fixed Charge Cov. (%) | 130 | 131 | 157 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '04-'06 to '10-'12 |
|---|---|---|---|
| Revenues | 5.0% | 1.5% | 4.0% |
| "Cash Flow" | 1.0% | 3.5% | 3.0% |
| Earnings | -3.0% | 1.5% | 4.0% |
| Dividends | -- | NMF | 7.0% |
| Book Value | 32.5% | 9.5% | 4.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | 270.1 | 290.1 | 335.3 | 273.5 | 1169.0 |
| 2005 | 260.9 | 300.6 | 349.3 | 318.7 | 1229.5 |
| 2006 | 305.0 | 318.4 | 375.6 | 317.9 | 1316.9 |
| 2007 | 317.8 | 329.8 | 398.2 | 334.2 | 1380 |
| 2008 | 345 | 360 | 415 | 350 | 1470 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .18 | .37 | .68 | .08 | 1.31 |
| 2005 | d.11 | .27 | .49 | .65 | 1.30 |
| 2006 | .52 | .28 | .73 | .32 | 1.85 |
| 2007 | .14 | .33 | .66 | .47 | 1.60 |
| 2008 | .25 | .35 | .75 | .40 | 1.75 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .16 | .16 | .16 | .16 | .64 |
| 2005 | .19 | .19 | .19 | .19 | .76 |
| 2006 | .21 | .21 | .21 | .21 | .84 |
| 2007 | .225 | .225 | .225 | .225 | .90 |
| 2008 | | | | | |

**BUSINESS:** UniSource Energy Corp., parent of Tucson Electric Power Company, supplies electricity in Tucson, Arizona and the surround. area (serv. area: 1,155 sq. miles). Nonutility subsidiaries engage in plant construction, fuel supply, and related businesses. Revenue sources: residential, 44%; commercial, 26%; industrial, 21%; other, 9%. Copper mining is largest industry served. Fuels: coal, 81%; gas, 6%; purchased power, 13%. Fuel: 46% of electric revenues; labor costs: 9%. '06 depreciation rate: 3.1%. Estimated plant age: 10 years. Has 1,260 employees. Chairman, President, and CEO: James S. Pignatelli. Inc.: AZ. Address: One South Church Ave. Suite 1820, Tucson, AZ 85701. Tel.: 520-884-3650. Internet: www.unisourceenergy.com.

**UniSource seeks higher rates.** A 1999 agreement froze electric rates through the end of 2008. As required by regulators, UNS filed for new rates that would take effect in January, 2009. It recommended that the commission use one of three methods in setting new tariffs. In all three cases, transmission and distribution rates are based on historic cost-based calculations. But rates for generated power are figured differently under each approach. In the first instance, charges would be based on wholesale market prices. An alternative ties rates to historic costs, subject to a separate charge. Either procedure would raise annual rates by about 22%. A third option blends the first two and results in lesser rates. All proposals reward customers for energy conservation. An order on the application will take effect January 1, 2009.

**Financial indicators will remain weak for a while.** Though long-term debt has been reduced steadily since 1996, it still accounts for about 70% of total capital. What's more, meaningful reductions are unlikely for a while because of the need to finance the capital spending program. That, in turn, keeps pressure on fixed charges, which have been barely earned since 1997. Too, though a large percentage of profits are being plowed back into retained earnings, this account still had a negative balance last September, 30th. Finally, UNS is having difficulty earning its allowed return on equity. In view of these negatives, we rate the company's Financial Strength a below-average C++.

**Earnings should improve in 2008.** Planned and unplanned plant outages, which took a toll in last year's first quarter, are behind the company. UNS should also benefit from an order on a filing for $9 million in higher posted gas tariffs. In all, we think 2008 earnings will rise 9% over last year's estimated $1.60 a share. An order on the aforementioned electric rate filing suggests a further gain next year. The stock is untimely.

**These shares offer an even balance of pluses and minuses.** Above-average dividend growth prospects to 2010-2012 might interest income-oriented investors. But those of a conservative bent may hesitate because of the company's weak finances.

*Arthur H. Medalie* *February 8, 2008*

(A) EPS diluted. Next earnings report due late Feb. Excl. nonrecur. gains (losses): '91, ($12.49); '92, 18¢; '93, ($0.11); '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00.
(B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '06: $6.38/sh. (D) In millions, adjusted for split. (E) Rate base: fair value. Rate allowed on com. eq. in '94: 11.0%; earned on avg. com. eq., '06: 10.3%. Regulatory Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | C++ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 90 |
| Earnings Predictability | 40 |

**TUCSON ELECTRIC POWER COMPANY**
**DOCKET NO. E-01933A-07-0402**
**TABLE OF CONTENTS TO SCHEDULES WAR**

**TUCSON ELECTRIC POWER COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2006**
**COST OF CAPITAL SUMMARY**



## WEIGHTED COST OF CAPITAL

| LINE NO. | DESCRIPTION | (A) COPANY PROPOSED | (B) RUCO ADJUSTMENT | (C) RUCO ADJUSTED | (D) CAPITAL RATIO | (E) RUCO COST | (F) WEIGHTED COST |
|---|---|---|---|---|---|---|---|
| 1 | LONG-TERM DEBT | $ 805,636 | $ - | $ 805,636 | 55.00% | 6.39% | 3.51% |
| 2 | COMMON EQUITY | 659,157 | - | 659,157 | 45.00% | 9.44% | 4.25% |
| 3 | TOTAL CAPITALIZATION | $ 1,464,793 | $ - | $ 1,464,793 | 100.00% | | |
| 4 | **WEIGHTED COST OF CAPITAL** | | | | | | 7.76% |

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) - COLUMN (B)
COLUMN (D): LINE 1 ÷ LINE 3
LINE 2 ÷ LINE 3
COLUMN (E): LINE 1 - SCHEDULE WAR-1, PAGE 2, LINE 37
LINE 2 - SCHEDULE WAR-1, PAGE 3, LINE 7
COLUMN (F): COLUMN (D) x COLUMN (E)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
COST OF CAPITAL SUMMARY

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 1
PAGE 2 OF 3

## COST OF LONG-TERM DEBT

| LINE NO. | (A) DESCRIPTION | (B) OUTSTANDING BALANCE ($000) | (C) ANNUAL INTEREST ($000) | (D) COST RATE (%) |
|---|---|---|---|---|
| 1 | MORTGAGE BONDS | | | |
| 2 | 7.50% SERIES FIRST COLLATERAL TRUST BONDS | $ 138,300 | $ 10,373 | |
| 3 | TOTAL FIRST MORTGAGE BONDS | $ 138,300 | $ 10,373 | 7.50% |
| 4 | | | | |
| 5 | VARIABLE RATE-TAX EXEMPT BONDS | | | |
| 6 | VARIABLE 1982 PIMA A IRVINGTON | $ 38,700 | $ 1,872 | |
| 7 | VARIABLE 1982 PIMA A IRVINGTON & FOUR CORNERS | 39,900 | 1,889 | |
| 8 | VARIABLE 1982 APACHE A SPRINGERVILLE | 100,000 | 4,786 | |
| 9 | VARIABLE 1983 APACHE B SPRINGERVILLE | 80,000 | 3,788 | |
| 10 | VARIABLE 1983 APACHE C SPRINGERVILLE | 50,000 | 2,340 | |
| 11 | VARIABLE 1985 APACHE A SPRINGERVILLE | 20,000 | 956 | |
| 12 | TOTAL VARIABLE RATE-TAX EXEMPT BONDS | $ 328,600 | $ 15,631 | 4.76% |
| 13 | | | | |
| 14 | | | | |
| 15 | FIXED RATE-TAX EXEMPT BONDS | | | |
| 16 | 6.10% 1997 PIMA A | $ 22,460 | $ 1,370 | |
| 17 | 5.85% 1998 APACHE C | 16,500 | 965 | |
| 18 | 6.95% 1997 FARMINGTON A | 80,410 | 5,588 | |
| 19 | 7.125% 1997 COCONINO A | 36,700 | 2,615 | |
| 20 | 7.00% 1997 COCONINO B | 14,700 | 1,029 | |
| 21 | 5.85% 1998 APACHE A | 83,700 | 4,896 | |
| 22 | 5.85% 1998 APACHE B | 99,800 | 5,863 | |
| 23 | TOTAL FIXED RATE-TAX EXEMPT BONDS | $ 354,270 | $ 22,326 | 6.30% |
| 24 | | | | |
| 25 | TOTAL LONG-TERM DEBT | $ 821,170 | $ 48,330 | 5.89% |
| 26 | | | | |
| 27 | UNAMORTIZED DEBT DISCOUNT, PREMIUM AND | | | |
| 28 | EXPENSE AND LOSS ON REAQUIRED DEBT | $ (15,534) | | |
| 29 | | | | |
| 30 | AMORTIZATION OF DEBT DISCOUNT AND | | | |
| 31 | EXPENSE AND LOSS ON REAQUIRED DEBT | | 2,971 | |
| 32 | | | | |
| 33 | CREDIT FACILITY COMMITMENT FEES | | 165 | |
| 34 | | | | |
| 35 | TOTAL LONG-TERM DEBT - NET | $ 805,636 | $ 51,466 | |
| 36 | | | | |
| 37 | TOTAL COST OF LONG-TERM DEBT | | | 6.39% |

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (B): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (C): COMPANY SCHEDULE D-2, PAGE 1

## COST OF COMMON EQUITY CALCULATION

| LINE NO. | | | |
|---|---|---|---|
| 1 | **DCF METHODOLOGY** | | |
| 2 | DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE | 8.62% | SCHEDULE WAR-2, COLUMN (C), LINE 27 |
| 3 | **CAPM METHODOLOGY** | | |
| 4 | CAPM - GEOMETRIC MEAN ESTIMATE | 9.42% | SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 27 |
| 5 | CAPM - ARITHMETIC MEAN ESTIMATE | 11.08% | SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 27 |
| 6 | AVERAGE OF CAPM ESTIMATES | 10.25% | ( LINE 4 + LINE 5 ) ÷ 2 |
| 7 | **AVERAGE** | 9.44% | ( LINE 2 + LINE 6 ) ÷ 2 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2006**
**DCF COST OF EQUITY CAPITAL**

**DOCKET NO. E-01933A-07-0402**
**SCHEDULE WAR - 2**

| LINE NO. | STOCK SYMBOL | COMPANY NAME | (A) DIVIDEND YIELD | + | (B) GROWTH RATE (g) | = | (C) DCF COST OF EQUITY CAPITAL |
|---|---|---|---|---|---|---|---|
| 1 | ALE | ALLETTE, INC. | 4.26% | + | 5.45% | = | 9.71% |
| 2 | LNT | ALLIANT ENERGY | 3.53% | + | 5.25% | = | 8.78% |
| 3 | AEE | AMEREN CORP. | 5.05% | + | 2.52% | = | 7.57% |
| 4 | AEP | AMERICAN ELECTRIC POWER COMPANY, INC. | 3.57% | + | 6.03% | = | 9.60% |
| 5 | CHG | CH ENERGY GROUP, INC. | 5.29% | + | 2.50% | = | 7.79% |
| 6 | CV | CENTRAL VERMONT PUBLIC SERVICE CORPORATION | 3.06% | + | 3.73% | = | 6.78% |
| 7 | CNL | CLECO CORPORATION | 3.35% | + | 4.48% | = | 7.83% |
| 8 | ED | CONSOLIDATED EDISON, INC. | 4.97% | + | 3.38% | = | 8.36% |
| 9 | DTE | DTE ENERGY COMPANY | 4.79% | + | 2.50% | = | 7.29% |
| 10 | EDE | EMPIRE DISTRICT ELECTRIC COMPANY | 5.66% | + | 3.97% | = | 9.63% |
| 11 | FE | FIRSTENERGY CORP. | 2.74% | + | 7.26% | = | 10.00% |
| 12 | HE | HAWAIIAN ELECTRIC INDUSTRIES, INC. | 5.50% | + | 2.41% | = | 7.91% |
| 13 | IDA | IDACORP, INC. | 3.54% | + | 3.63% | = | 7.17% |
| 14 | MGEE | MGE ENERGY, INC. | 4.11% | + | 7.05% | = | 11.16% |
| 15 | NI | NISOURCE, INC. | 4.91% | + | 2.00% | = | 6.91% |
| 16 | NST | NSTAR | 4.05% | + | 6.01% | = | 10.06% |
| 17 | PNM | PNM RESOURCES | 4.46% | + | 2.70% | = | 7.16% |
| 18 | PNW | PINNACLE WEST CAPITAL CORPORATION | 5.11% | + | 2.02% | = | 7.13% |
| 19 | PPL | PPL CORPORATION | 2.39% | + | 11.26% | = | 13.65% |
| 20 | PGN | PROGRESSS ENERGY | 5.17% | + | 2.33% | = | 7.50% |
| 21 | SCG | SCANA CORPORATION | 4.33% | + | 4.03% | = | 8.36% |
| 22 | SO | SOUTHERN COMPANY | 4.23% | + | 5.01% | = | 9.23% |
| 23 | TE | TECO ENERGY, INC. | 4.62% | + | 4.72% | = | 9.34% |
| 24 | UIL | UIL HOLDINGS | 4.89% | + | 2.56% | = | 7.44% |
| 25 | VVC | VECTREN | 4.56% | + | 4.81% | = | 9.37% |
| 26 | XEL | XCEL ENERGY INC. | 4.19% | + | 4.24% | = | 8.43% |
| 27 | **AVERAGE** | | | | | | 8.62% |

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

**TUCSON ELECTRIC POWER COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2006**
**DIVIDEND YIELD CALCULATION**

**DOCKET NO. E-01933A-07-0402**
**SCHEDULE WAR - 3**

| LINE NO. | STOCK SYMBOL | COMPANY NAME | (A) ESTIMATED DIVIDEND (PER SHARE) | ÷ | (B) AVERAGE STOCK PRICE (PER SHARE) | = | (C) DIVIDEND YIELD |
|---|---|---|---|---|---|---|---|
| 1 | ALE | ALLETTE, INC. | $ 1.64 | ÷ | $ 38.50 | = | 4.26% |
| 2 | LNT | ALLIANT ENERGY | 1.40 | ÷ | 39.68 | = | 3.53% |
| 3 | AEE | AMEREN CORP. | 2.54 | ÷ | 50.32 | = | 5.05% |
| 4 | AEP | AMERICAN ELECTRIC POWER COMPANY, INC. | 1.64 | ÷ | 45.92 | = | 3.57% |
| 5 | CHG | CH ENERGY GROUP, INC. | 2.16 | ÷ | 40.81 | = | 5.29% |
| 6 | CV | CENTRAL VERMONT PUBLIC SERVICE CORPORATION | 0.92 | ÷ | 30.10 | = | 3.06% |
| 7 | CNL | CLECO CORPORATION | 0.90 | ÷ | 26.88 | = | 3.35% |
| 8 | ED | CONSOLIDATED EDISON, INC. | 2.32 | ÷ | 46.68 | = | 4.97% |
| 9 | DTE | DTE ENERGY COMPANY | 2.12 | ÷ | 44.27 | = | 4.79% |
| 10 | EDE | EMPIRE DISTRICT ELECTRIC COMPANY | 1.28 | ÷ | 22.60 | = | 5.66% |
| 11 | FE | FIRSTENERGY CORP. | 2.00 | ÷ | 72.89 | = | 2.74% |
| 12 | HE | HAWAIIAN ELECTRIC INDUSTRIES, INC. | 1.24 | ÷ | 22.53 | = | 5.50% |
| 13 | IDA | IDACORP, INC. | 1.20 | ÷ | 33.87 | = | 3.54% |
| 14 | MGEE | MGE ENERGY, INC. | 1.42 | ÷ | 34.51 | = | 4.11% |
| 15 | NI | NISOURCE, INC. | 0.92 | ÷ | 18.74 | = | 4.91% |
| 16 | NST | NSTAR | 1.40 | ÷ | 34.53 | = | 4.05% |
| 17 | PNM | PNM RESOURCES | 0.92 | ÷ | 20.61 | = | 4.46% |
| 18 | PNW | PINNACLE WEST CAPITAL CORPORATION | 2.10 | ÷ | 41.08 | = | 5.11% |
| 19 | PPL | PPL CORPORATION | 1.22 | ÷ | 51.13 | = | 2.39% |
| 20 | PGN | PROGRESSS ENERGY | 2.44 | ÷ | 47.20 | = | 5.17% |
| 21 | SCG | SCANA CORPORATION | 1.76 | ÷ | 40.61 | = | 4.33% |
| 22 | SO | SOUTHERN COMPANY | 1.61 | ÷ | 38.15 | = | 4.23% |
| 23 | TE | TECO ENERGY, INC. | 0.78 | ÷ | 16.88 | = | 4.62% |
| 24 | UIL | UIL HOLDINGS | 1.73 | ÷ | 35.35 | = | 4.89% |
| 25 | VVC | VECTREN | 1.30 | ÷ | 28.50 | = | 4.56% |
| 26 | XEL | XCEL ENERGY INC. | 0.92 | ÷ | 21.98 | = | 4.19% |
| 27 | **AVERAGE** | | | | | | 4.32% |

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 12/10/2007 TO 02/08/2008 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 4


| LINE NO. | STOCK SYMBOL | COMPANY NAME | (A) INTERNAL GROWTH ( br ) | + | (B) EXTERNAL GROWTH (sv) | = | (C) DIVIDEND GROWTH (g) |
|---|---|---|---|---|---|---|---|
| 1 | ALE | ALLETTE, INC. | 5.00% | + | 0.45% | = | 5.45% |
| 2 | LNT | ALLIANT ENERGY | 5.25% | + | 0.00% | = | 5.25% |
| 3 | AEE | AMEREN CORP. | 2.25% | + | 0.27% | = | 2.52% |
| 4 | AEP | AMERICAN ELECTRIC POWER COMPANY, INC. | 5.65% | + | 0.38% | = | 6.03% |
| 5 | CHG | CH ENERGY GROUP, INC. | 2.50% | + | 0.00% | = | 2.50% |
| 6 | CV | CENTRAL VERMONT PUBLIC SERVICE CORPORATION | 3.25% | + | 0.48% | = | 3.73% |
| 7 | CNL | CLECO CORPORATION | 3.50% | + | 0.98% | = | 4.48% |
| 8 | ED | CONSOLIDATED EDISON, INC. | 2.75% | + | 0.63% | = | 3.38% |
| 9 | DTE | DTE ENERGY COMPANY | 2.50% | + | 0.00% | = | 2.50% |
| 10 | EDE | EMPIRE DISTRICT ELECTRIC COMPANY | 2.25% | + | 1.72% | = | 3.97% |
| 11 | FE | FIRSTENERGY CORP. | 7.25% | + | 0.01% | = | 7.26% |
| 12 | HE | HAWAIIAN ELECTRIC INDUSTRIES, INC. | 1.75% | + | 0.66% | = | 2.41% |
| 13 | IDA | IDACORP, INC. | 3.25% | + | 0.38% | = | 3.63% |
| 14 | MGEE | MGE ENERGY, INC. | 5.50% | + | 1.55% | = | 7.05% |
| 15 | NI | NISOURCE, INC. | 2.00% | + | 0.00% | = | 2.00% |
| 16 | NST | NSTAR | 6.00% | + | 0.01% | = | 6.01% |
| 17 | PNM | PNM RESOURCES | 2.75% | + | -0.05% | = | 2.70% |
| 18 | PNW | PINNACLE WEST CAPITAL CORPORATION | 2.00% | + | 0.02% | = | 2.02% |
| 19 | PPL | PPL CORPORATION | 11.25% | + | 0.01% | = | 11.26% |
| 20 | PGN | PROGRESSS ENERGY | 2.00% | + | 0.33% | = | 2.33% |
| 21 | SCG | SCANA CORPORATION | 4.00% | + | 0.03% | = | 4.03% |
| 22 | SO | SOUTHERN COMPANY | 3.50% | + | 1.51% | = | 5.01% |
| 23 | TE | TECO ENERGY, INC. | 4.50% | + | 0.22% | = | 4.72% |
| 24 | UIL | UIL HOLDINGS | 2.00% | + | 0.56% | = | 2.56% |
| 25 | VVC | VECTREN | 3.50% | + | 1.31% | = | 4.81% |
| 26 | XEL | XCEL ENERGY INC. | 3.50% | + | 0.74% | = | 4.24% |
| 27 | **AVERAGE** | | | | | | 4.30% |

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

**TUCSON ELECTRIC POWER COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2006**
**DIVIDEND GROWTH RATE CALCULATION**

**DOCKET NO. E-01933A-07-0402**
**SCHEDULE WAR - 4**
**PAGE 2 OF 2**

| LINE NO. | STOCK SYMBOL | COMPANY NAME | (A) SHARE GROWTH | x | (B) { [ ( ( M ÷ B ) + 1 ) ÷ 2 ] - 1 } | = | (C) EXTERNAL GROWTH ( sv ) |
|---|---|---|---|---|---|---|---|
| 1 | ALE | ALLETTE, INC. | 1.40% | x | { [ ( ( 1.65 ) + 1 ) ÷ 2 ] - 1 } | = | 0.45% |
| 2 | LNT | ALLIANT ENERGY | 0.01% | x | { [ ( ( 1.77 ) + 1 ) ÷ 2 ] - 1 } | = | 0.00% |
| 3 | AEE | AMEREN CORP. | 1.00% | x | { [ ( ( 1.54 ) + 1 ) ÷ 2 ] - 1 } | = | 0.27% |
| 4 | AEP | AMERICAN ELECTRIC POWER COMPANY, INC. | 0.90% | x | { [ ( ( 1.84 ) + 1 ) ÷ 2 ] - 1 } | = | 0.38% |
| 5 | CHG | CH ENERGY GROUP, INC. | 0.01% | x | { [ ( ( 1.23 ) + 1 ) ÷ 2 ] - 1 } | = | 0.00% |
| 6 | CV | CENTRAL VERMONT PUBLIC SERVICE CORPORATION | 1.50% | x | { [ ( ( 1.64 ) + 1 ) ÷ 2 ] - 1 } | = | 0.48% |
| 7 | CNL | CLECO CORPORATION | 3.00% | x | { [ ( ( 1.65 ) + 1 ) ÷ 2 ] - 1 } | = | 0.98% |
| 8 | ED | CONSOLIDATED EDISON, INC. | 3.50% | x | { [ ( ( 1.36 ) + 1 ) ÷ 2 ] - 1 } | = | 0.63% |
| 9 | DTE | DTE ENERGY COMPANY | 0.01% | x | { [ ( ( 1.26 ) + 1 ) ÷ 2 ] - 1 } | = | 0.00% |
| 10 | EDE | EMPIRE DISTRICT ELECTRIC COMPANY | 8.50% | x | { [ ( ( 1.40 ) + 1 ) ÷ 2 ] - 1 } | = | 1.72% |
| 11 | FE | FIRSTENERGY CORP. | 0.01% | x | { [ ( ( 2.52 ) + 1 ) ÷ 2 ] - 1 } | = | 0.01% |
| 12 | HE | HAWAIIAN ELECTRIC INDUSTRIES, INC. | 2.00% | x | { [ ( ( 1.66 ) + 1 ) ÷ 2 ] - 1 } | = | 0.66% |
| 13 | IDA | IDACORP, INC. | 2.50% | x | { [ ( ( 1.30 ) + 1 ) ÷ 2 ] - 1 } | = | 0.38% |
| 14 | MGEE | MGE ENERGY, INC. | 3.00% | x | { [ ( ( 2.03 ) + 1 ) ÷ 2 ] - 1 } | = | 1.55% |
| 15 | NI | NISOURCE, INC. | 0.30% | x | { [ ( ( 1.01 ) + 1 ) ÷ 2 ] - 1 } | = | 0.00% |
| 16 | NST | NSTAR | 0.01% | x | { [ ( ( 2.21 ) + 1 ) ÷ 2 ] - 1 } | = | 0.01% |
| 17 | PNM | PNM RESOURCES | 1.25% | x | { [ ( ( 0.92 ) + 1 ) ÷ 2 ] - 1 } | = | -0.05% |
| 18 | PNW | PINNACLE WEST CAPITAL CORPORATION | 0.25% | x | { [ ( ( 1.16 ) + 1 ) ÷ 2 ] - 1 } | = | 0.02% |
| 19 | PPL | PPL CORPORATION | 0.01% | x | { [ ( ( 3.68 ) + 1 ) ÷ 2 ] - 1 } | = | 0.01% |
| 20 | PGN | PROGRESSS ENERGY | 1.50% | x | { [ ( ( 1.44 ) + 1 ) ÷ 2 ] - 1 } | = | 0.33% |
| 21 | SCG | SCANA CORPORATION | 0.10% | x | { [ ( ( 1.60 ) + 1 ) ÷ 2 ] - 1 } | = | 0.03% |
| 22 | SO | SOUTHERN COMPANY | 2.25% | x | { [ ( ( 2.34 ) + 1 ) ÷ 2 ] - 1 } | = | 1.51% |
| 23 | TE | TECO ENERGY, INC. | 0.50% | x | { [ ( ( 1.89 ) + 1 ) ÷ 2 ] - 1 } | = | 0.22% |
| 24 | UIL | UIL HOLDINGS | 1.25% | x | { [ ( ( 1.89 ) + 1 ) ÷ 2 ] - 1 } | = | 0.56% |
| 25 | VVC | VECTREN | 3.75% | x | { [ ( ( 1.70 ) + 1 ) ÷ 2 ] - 1 } | = | 1.31% |
| 26 | XEL | XCEL ENERGY INC. | 3.00% | x | { [ ( ( 1.50 ) + 1 ) ÷ 2 ] - 1 } | = | 0.74% |
| 27 | **AVERAGE** | | | | | | 0.47% |

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS



| LINE NO. | STOCK SYMBOL | COMPANY NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALE | ALLETTE, INC. | 2002 | NMF | | - | | NMF | - | - | |
| 2 | | | 2003 | NMF | | - | | NMF | - | - | |
| 3 | | | 2004 | 0.7778 | | 6.10% | | 4.74% | 21.23 | 29.70 | |
| 4 | | | 2005 | 0.4960 | | 11.30% | | 5.60% | 20.03 | 30.10 | |
| 5 | | | 2006 | 0.4765 | | 11.60% | | 5.53% | 21.90 | 30.40 | |
| 6 | | | GROWTH 2002 - 2006 | | | | | 5.29% | - | | 0.58% |
| 7 | | | 2007 | 0.4533 | | 11.50% | | 5.21% | | 30.85 | 1.48% |
| 8 | | | 2008 | 0.3778 | | 10.00% | | 3.78% | | 31.30 | 1.47% |
| 9 | | | 2010-12 | 0.4857 | | 10.50% | | 5.10% | 5.50% | 32.50 | 1.34% |
| 10 | | | | | | | | | | | |
| 11 | LNT | ALLIANT ENERGY | 2002 | -0.6949 | | 5.80% | | NMF | 19.89 | 92.30 | |
| 12 | | | 2003 | 0.3631 | | 6.70% | | 2.43% | 21.37 | 110.96 | |
| 13 | | | 2004 | 0.4486 | | 8.20% | | 3.68% | 22.13 | 115.74 | |
| 14 | | | 2005 | 0.5249 | | 13.10% | | 6.88% | 20.85 | 117.07 | |
| 15 | | | 2006 | 0.4417 | | 9.10% | | 4.02% | 22.83 | 116.13 | |
| 16 | | | GROWTH 2002 - 2006 | | | | | 4.25% | -2.50% | | 5.91% |
| 17 | | | 2007 | 0.5115 | | 12.00% | | 6.14% | | 107.20 | -7.69% |
| 18 | | | 2008 | 0.4717 | | 11.00% | | 5.19% | | 108.00 | -3.56% |
| 19 | | | 2010-12 | 0.4035 | | 10.50% | | 4.24% | 4.00% | 111.00 | -0.90% |
| 20 | | | | | | | | | | | |
| 21 | AEE | AMEREN CORP. | 2002 | 0.0451 | | 9.90% | | 0.45% | 24.93 | 154.10 | |
| 22 | | | 2003 | 0.1911 | | 11.60% | | 2.22% | 26.73 | 162.90 | |
| 23 | | | 2004 | 0.0993 | | 9.10% | | 0.90% | 29.71 | 195.20 | |
| 24 | | | 2005 | 0.1885 | | 9.70% | | 1.83% | 31.09 | 204.70 | |
| 25 | | | 2006 | 0.0451 | | 8.10% | | 0.37% | 31.86 | 206.60 | |
| 26 | | | GROWTH 2002 - 2006 | | | | | 1.15% | 5.50% | | 7.60% |
| 27 | | | 2007 | 0.2185 | | 10.00% | | 2.18% | | 208.80 | 1.06% |
| 28 | | | 2008 | 0.2303 | | 10.00% | | 2.30% | | 210.80 | 1.01% |
| 29 | | | 2010-12 | 0.2529 | | 9.00% | | 2.28% | 3.00% | 216.80 | 0.97% |
| 30 | | | | | | | | | | | |
| 31 | AEP | AMERICAN ELECTRIC POWER COMPANY, INC. | 2002 | 0.1608 | | 13.70% | | 2.20% | 20.85 | 338.84 | |
| 32 | | | 2003 | 0.3478 | | 12.40% | | 4.31% | 19.93 | 395.02 | |
| 33 | | | 2004 | 0.4636 | | 12.20% | | 5.66% | 21.32 | 395.86 | |
| 34 | | | 2005 | 0.4621 | | 11.30% | | 5.22% | 23.08 | 393.72 | |
| 35 | | | 2006 | 0.4755 | | 12.00% | | 5.71% | 23.73 | 396.67 | |
| 36 | | | GROWTH 2002 - 2006 | | | | | 4.62% | -2.50% | | 4.02% |
| 37 | | | 2007 | 0.4357 | | 11.00% | | 4.79% | | 400.50 | 0.97% |
| 38 | | | 2008 | 0.4698 | | 12.00% | | 5.64% | | 404.00 | 0.92% |
| 39 | | | 2010-12 | 0.4500 | | 12.50% | | 5.63% | 6.00% | 413.00 | 0.81% |

REFERENCES: RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007.
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
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COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

**TUCSON ELECTRIC POWER COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2006**
**DIVIDEND GROWTH COMPONENTS**

**DOCKET NO. E-01933A-07-0402**
**SCHEDULE WAR - 5**


| LINE NO. | STOCK SYMBOL | LOCAL DISTRIBUTION COMPANY NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | CHG | CH ENERGY GROUP, INC. | 2002 | -0.0189 | | 7.10% | | NMF | 30.31 | 16.06 | |
| 2 | | | 2003 | 0.2230 | | 9.10% | | 2.03% | 30.80 | 15.76 | |
| 3 | | | 2004 | 0.1970 | | 8.60% | | 1.69% | 31.31 | 15.76 | |
| 4 | | | 2005 | 0.2313 | | 8.80% | | 2.04% | 31.97 | 15.76 | |
| 5 | | | 2006 | 0.1563 | | 7.90% | | 1.23% | 32.54 | 15.76 | |
| 6 | | | GROWTH 2002 - 2006 | | | | | 1.75% | 1.50% | | -0.47% |
| 7 | | | 2007 | 0.1692 | | 8.00% | | 1.35% | | 15.76 | 0.00% |
| 8 | | | 2008 | 0.2286 | | 8.50% | | 1.94% | | 15.76 | 0.00% |
| 9 | | | 2010-12 | 0.3046 | | 9.00% | | 2.74% | 2.00% | 15.00 | -0.98% |
| 10 | | | | | | | | | | | |
| 11 | CV | CENTRAL VERMONT PUBLIC SERVICE CORPORATION | 2002 | 0.4286 | | 9.30% | | 3.99% | 16.83 | 11.74 | |
| 12 | | | 2003 | 0.3759 | | 8.10% | | 3.04% | 17.89 | 11.81 | |
| 13 | | | 2004 | 0.2640 | | 6.80% | | 1.80% | 18.49 | 12.19 | |
| 14 | | | 2005 | -10.5000 | | 0.50% | | NMF | 17.70 | 12.28 | |
| 15 | | | 2006 | 0.4356 | | 10.10% | | 4.40% | 17.70 | 10.13 | |
| 16 | | | GROWTH 2002 - 2006 | | | | | 3.31% | 2.00% | | -3.62% |
| 17 | | | 2007 | 0.3429 | | 7.50% | | 2.57% | | 10.30 | 1.68% |
| 18 | | | 2008 | 0.3867 | | 8.00% | | 3.09% | | 10.40 | 1.32% |
| 19 | | | 2010-12 | 0.4424 | | 8.00% | | 3.54% | 3.00% | 10.70 | 1.10% |
| 20 | | | | | | | | | | | |
| 21 | CNL | CLECO CORPORATION | 2002 | 0.4079 | | 13.10% | | 5.34% | 11.77 | 47.04 | |
| 22 | | | 2003 | 0.2857 | | 12.50% | | 3.57% | 10.09 | 47.18 | |
| 23 | | | 2004 | 0.3182 | | 11.90% | | 3.79% | 10.83 | 49.62 | |
| 24 | | | 2005 | 0.3662 | | 10.70% | | 3.92% | 13.69 | 49.99 | |
| 25 | | | 2006 | 0.3382 | | 8.30% | | 2.81% | 15.22 | 57.57 | |
| 26 | | | GROWTH 2002 - 2006 | | | | | 3.89% | 5.50% | | 5.18% |
| 27 | | | 2007 | 0.3077 | | 8.00% | | 2.46% | | 60.00 | 4.22% |
| 28 | | | 2008 | 0.4000 | | 9.00% | | 3.60% | | 61.00 | 2.94% |
| 29 | | | 2010-12 | 0.3500 | | 10.50% | | 3.68% | 6.50% | 64.00 | 2.14% |
| 30 | | | | | | | | | | | |
| 31 | ED | CONSOLIDATED EDISON, INC. | 2002 | 0.2907 | | 11.30% | | 3.29% | 27.68 | 213.93 | |
| 32 | | | 2003 | 0.2085 | | 9.80% | | 2.04% | 28.44 | 225.84 | |
| 33 | | | 2004 | 0.0259 | | 7.80% | | 0.20% | 29.09 | 242.51 | |
| 34 | | | 2005 | 0.2375 | | 9.70% | | 2.30% | 29.80 | 245.29 | |
| 35 | | | 2006 | 0.2203 | | 9.20% | | 2.03% | 31.09 | 257.46 | |
| 36 | | | GROWTH 2002 - 2006 | | | | | 1.97% | 3.00% | | 4.74% |
| 37 | | | 2007 | 0.2970 | | 9.50% | | 2.82% | | 272.00 | 5.65% |
| 38 | | | 2008 | 0.3118 | | 9.50% | | 2.96% | | 273.00 | 2.97% |
| 39 | | | 2010-12 | 0.3143 | | 8.50% | | 2.67% | 5.00% | 278.00 | 1.55% |

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
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TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
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| LINE NO. | STOCK SYMBOL | LOCAL DISTRIBUTION COMPANY NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | DTE | DTE ENERGY COMPANY | 2002 | 0.4621 | | 13.80% | | 6.38% | 27.26 | 167.46 | |
| 2 | | | 2003 | 0.2772 | | 9.10% | | 2.52% | 31.36 | 168.61 | |
| 3 | | | 2004 | 0.1922 | | 8.00% | | 1.54% | 31.85 | 174.21 | |
| 4 | | | 2005 | 0.3700 | | 10.00% | | 3.70% | 32.44 | 177.81 | |
| 5 | | | 2006 | 0.1510 | | 7.50% | | 1.13% | 33.02 | 177.14 | |
| 6 | | | GROWTH 2002 - 2006 | | | | | 3.05% | 3.00% | | 1.41% |
| 7 | | | 2007 | 0.3049 | | 9.00% | | 2.74% | | 162.50 | -8.26% |
| 8 | | | 2008 | 0.2351 | | 8.00% | | 1.88% | | 157.00 | -5.86% |
| 9 | | | 2010-12 | 0.3143 | | 9.00% | | 2.83% | 2.50% | 157.00 | -2.38% |
| 10 | | | | | | | | | | | |
| 11 | EDE | EMPIRE DISTRICT ELECTRIC COMPANY | 2002 | -0.0756 | | 7.80% | | NMF | 14.59 | 22.57 | |
| 12 | | | 2003 | 0.0078 | | 7.80% | | 0.06% | 15.17 | 24.98 | |
| 13 | | | 2004 | -0.4884 | | 5.80% | | NMF | 14.76 | 25.70 | |
| 14 | | | 2005 | -0.3913 | | 6.00% | | NMF | 15.08 | 26.08 | |
| 15 | | | 2006 | 0.0922 | | 8.50% | | 0.78% | 15.49 | 30.25 | |
| 16 | | | GROWTH 2002 - 2006 | | | | | 0.42% | 2.00% | | 7.60% |
| 17 | | | 2007 | -0.0240 | | 7.00% | | NMF | | 34.25 | 13.22% |
| 18 | | | 2008 | 0.1172 | | 8.50% | | 1.00% | | 35.80 | 8.79% |
| 19 | | | 2010-12 | 0.2286 | | 10.50% | | 2.40% | 3.00% | 36.00 | 3.54% |
| 20 | | | | | | | | | | | |
| 21 | FE | FIRSTENERGY CORP. | 2002 | 0.4094 | | 10.50% | | 4.30% | 23.92 | 297.64 | |
| 22 | | | 2003 | -0.0204 | | 5.40% | | NMF | 25.13 | 329.84 | |
| 23 | | | 2004 | 0.3105 | | 10.60% | | 3.29% | 26.04 | 329.84 | |
| 24 | | | 2005 | 0.3979 | | 10.20% | | 4.06% | 27.86 | 329.84 | |
| 25 | | | 2006 | 0.5157 | | 13.90% | | 7.17% | 28.30 | 319.21 | |
| 26 | | | GROWTH 2002 - 2006 | | | | | 4.70% | 4.50% | | 1.76% |
| 27 | | | 2007 | 0.5224 | | 15.00% | | 7.84% | | 304.80 | -4.51% |
| 28 | | | 2008 | 0.5000 | | 14.00% | | 7.00% | | 304.80 | -2.28% |
| 29 | | | 2010-12 | 0.5238 | | 13.50% | | 7.07% | 6.00% | 304.80 | -0.92% |
| 30 | | | | | | | | | | | |
| 31 | HE | HAWAIIAN ELECTRIC INDUSTRIES, INC. | 2002 | 0.2346 | | 11.30% | | 2.65% | 14.21 | 73.62 | |
| 32 | | | 2003 | 0.2152 | | 10.80% | | 2.32% | 14.36 | 75.84 | |
| 33 | | | 2004 | 0.0882 | | 8.90% | | 0.79% | 15.01 | 80.69 | |
| 34 | | | 2005 | 0.1507 | | 9.70% | | 1.46% | 15.02 | 80.98 | |
| 35 | | | 2006 | 0.0677 | | 9.90% | | 0.67% | 13.44 | 81.46 | |
| 36 | | | GROWTH 2002 - 2006 | | | | | 1.58% | 2.00% | | 2.56% |
| 37 | | | 2007 | -0.3778 | | 6.50% | | NMF | | 83.50 | 2.50% |
| 38 | | | 2008 | 0.0080 | | 9.00% | | 0.07% | | 85.50 | 2.45% |
| 39 | | | 2010-12 | 0.1733 | | 11.00% | | 1.91% | -0.50% | 87.00 | 1.32% |

REFERENCES:

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TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS



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|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | IDA | IDACORP, INC. | 2002 | -0.1411 | | 7.00% | | NMF | 23.01 | 38.02 | |
| 2 | | | 2003 | -0.9375 | | 4.20% | | NMF | 22.54 | 38.34 | |
| 3 | | | 2004 | 0.1053 | | 7.20% | | 0.76% | 23.88 | 42.22 | |
| 4 | | | 2005 | 0.3143 | | 6.20% | | 1.95% | 24.04 | 42.66 | |
| 5 | | | 2006 | 0.4894 | | 8.90% | | 4.36% | 25.76 | 43.63 | |
| 6 | | | GROWTH 2002 - 2006 | | | | | 2.35% | 2.50% | | 3.50% |
| 7 | | | 2007 | 0.4000 | | 7.50% | | 3.00% | | 45.00 | 3.14% |
| 8 | | | 2008 | 0.4419 | | 7.50% | | 3.31% | | 46.30 | 3.01% |
| 9 | | | 2010-12 | 0.4667 | | 7.00% | | 3.27% | 4.00% | 47.50 | 1.71% |
| 10 | | | | | | | | | | | |
| 11 | MGEE | MGE ENERGY, INC. | 2002 | 0.2071 | | 12.80% | | 2.65% | 12.94 | 17.57 | |
| 12 | | | 2003 | 0.2105 | | 11.60% | | 2.44% | 14.34 | 18.34 | |
| 13 | | | 2004 | 0.2316 | | 10.00% | | 2.32% | 16.59 | 20.39 | |
| 14 | | | 2005 | 0.1274 | | 9.30% | | 1.18% | 16.81 | 20.45 | |
| 15 | | | 2006 | 0.3252 | | 11.30% | | 3.68% | 17.89 | 20.98 | |
| 16 | | | GROWTH 2002 - 2006 | | | | | 2.45% | 7.00% | | 4.53% |
| 17 | | | 2007 | 0.4000 | | 12.50% | | 5.00% | | 21.90 | 4.39% |
| 18 | | | 2008 | 0.4042 | | 13.50% | | 5.46% | | 21.90 | 2.17% |
| 19 | | | 2010-12 | 0.4231 | | 14.00% | | 5.92% | 7.00% | 21.90 | 0.86% |
| 20 | | | | | | | | | | | |
| 21 | NI | NISOURCE, INC. | 2002 | 0.3927 | | 9.70% | | 3.81% | 16.78 | 248.86 | |
| 22 | | | 2003 | 0.3082 | | 9.40% | | 2.90% | 16.81 | 262.63 | |
| 23 | | | 2004 | 0.4321 | | 9.00% | | 3.89% | 17.69 | 270.63 | |
| 24 | | | 2005 | 0.1481 | | 6.00% | | 0.89% | 18.09 | 272.62 | |
| 25 | | | 2006 | 0.1930 | | 6.30% | | 1.22% | 18.32 | 273.65 | |
| 26 | | | GROWTH 2002 - 2006 | | | | | 2.54% | 4.00% | | 2.40% |
| 27 | | | 2007 | 0.2333 | | 6.50% | | 1.52% | | 274.75 | 0.40% |
| 28 | | | 2008 | 0.2640 | | 6.50% | | 1.72% | | 275.50 | 0.34% |
| 29 | | | 2010-12 | 0.3333 | | 7.50% | | 2.50% | 2.00% | 277.00 | 0.24% |
| 30 | | | | | | | | | | | |
| 31 | NST | NSTAR | 2002 | 0.3669 | | 13.80% | | 5.06% | 12.25 | 106.07 | |
| 32 | | | 2003 | 0.3736 | | 13.70% | | 5.12% | 12.84 | 106.07 | |
| 33 | | | 2004 | 0.3580 | | 13.10% | | 4.69% | 13.52 | 106.55 | |
| 34 | | | 2005 | 0.5246 | | 12.80% | | 6.71% | 14.37 | 106.81 | |
| 35 | | | 2006 | 0.2021 | | 13.10% | | 2.65% | 14.82 | 106.81 | |
| 36 | | | GROWTH 2002 - 2006 | | | | | 4.85% | 2.50% | | 0.17% |
| 37 | | | 2007 | 0.3571 | | 13.50% | | 4.82% | | 106.81 | 0.00% |
| 38 | | | 2008 | 0.3644 | | 14.00% | | 5.10% | | 106.81 | 0.00% |
| 39 | | | 2010-12 | 0.4167 | | 14.50% | | 6.04% | 5.50% | 106.81 | 0.00% |

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TUCSON ELECTRIC POWER COMPANY
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|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | PNM | PNM RESOURCES | 2002 | 0.4673 | | 6.50% | | 3.04% | 16.60 | 58.68 | |
| 2 | | | 2003 | 0.4696 | | 6.30% | | 2.96% | 17.84 | 60.39 | |
| 3 | | | 2004 | 0.5594 | | 8.00% | | 4.48% | 18.19 | 60.46 | |
| 4 | | | 2005 | 0.5031 | | 8.20% | | 4.13% | 18.70 | 68.79 | |
| 5 | | | 2006 | 0.5000 | | 7.20% | | 3.60% | 22.09 | 76.65 | |
| 6 | | | GROWTH 2002 - 2006 | | | | | 3.64% | 4.50% | | 6.91% |
| 7 | | | 2007 | 0.3111 | | 5.50% | | 1.71% | | 77.00 | 0.46% |
| 8 | | | 2008 | 0.4121 | | 7.00% | | 2.88% | | 80.00 | 2.16% |
| 9 | | | 2010-12 | 0.4108 | | 7.00% | | 2.88% | 4.50% | 80.00 | 0.86% |
| 10 | | | | | | | | | | | |
| 11 | PNW | PINNACLE WEST CAPITAL CORPORATION | 2002 | 0.3557 | | 8.00% | | 2.85% | 29.44 | 91.26 | |
| 12 | | | 2003 | 0.3135 | | 8.10% | | 2.54% | 31.00 | 91.29 | |
| 13 | | | 2004 | 0.2907 | | 8.00% | | 2.33% | 32.14 | 91.79 | |
| 14 | | | 2005 | 0.1384 | | 6.50% | | 0.90% | 34.57 | 99.08 | |
| 15 | | | 2006 | 0.3596 | | 9.20% | | 3.31% | 34.47 | 99.96 | |
| 16 | | | GROWTH 2002 - 2006 | | | | | 2.38% | 4.00% | | 2.30% |
| 17 | | | 2007 | 0.2857 | | 8.50% | | 2.43% | | 100.40 | 0.44% |
| 18 | | | 2008 | 0.1686 | | 7.00% | | 1.18% | | 100.50 | 0.27% |
| 19 | | | 2010-12 | 0.2271 | | 8.00% | | 1.82% | 2.00% | 100.80 | 0.17% |
| 20 | | | | | | | | | | | |
| 21 | PPL | PPL CORPORATION | 2002 | 0.5325 | | 21.10% | | 11.24% | 6.71 | 331.47 | |
| 22 | | | 2003 | 0.5815 | | 19.60% | | 11.40% | 9.19 | 354.72 | |
| 23 | | | 2004 | 0.5615 | | 16.30% | | 9.15% | 11.21 | 378.14 | |
| 24 | | | 2005 | 0.5000 | | 16.70% | | 8.35% | 11.62 | 380.15 | |
| 25 | | | 2006 | 0.5197 | | 17.30% | | 8.99% | 13.30 | 385.04 | |
| 26 | | | GROWTH 2002 - 2006 | | | | | 9.83% | 14.00% | | 3.82% |
| 27 | | | 2007 | 0.5564 | | 20.50% | | 11.41% | | 372.00 | -3.39% |
| 28 | | | 2008 | 0.4531 | | 16.50% | | 7.48% | | 372.00 | -1.71% |
| 29 | | | 2010-12 | 0.5111 | | 23.50% | | 12.01% | 8.50% | 360.00 | -1.34% |
| 30 | | | | | | | | | | | |
| 31 | PGN | PROGRESSS ENERGY | 2002 | 0.4323 | | 12.10% | | 5.23% | 28.73 | 232.43 | |
| 32 | | | 2003 | 0.3372 | | 10.90% | | 3.68% | 30.26 | 246.00 | |
| 33 | | | 2004 | 0.2516 | | 9.90% | | 2.49% | 30.90 | 247.00 | |
| 34 | | | 2005 | 0.1905 | | 9.00% | | 1.71% | 31.90 | 252.00 | |
| 35 | | | 2006 | -0.1805 | | 6.10% | | NMF | 32.37 | 256.00 | |
| 36 | | | GROWTH 2002 - 2006 | | | | | 3.28% | 5.00% | | 2.44% |
| 37 | | | 2007 | 0.1552 | | 9.00% | | 1.40% | | 260.00 | 1.56% |
| 38 | | | 2008 | 0.1767 | | 9.00% | | 1.59% | | 264.00 | 1.55% |
| 39 | | | 2010-12 | 0.2333 | | 9.50% | | 2.22% | 1.50% | 274.00 | 1.37% |

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS



| LINE NO. | STOCK SYMBOL | LOCAL DISTRIBUTION COMPANY NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | SCG | SCANA CORPORATION | 2002 | 0.4538 | | 11.60% | | 5.26% | 19.64 | 110.83 | |
| 2 | | | 2003 | 0.4480 | | 12.10% | | 5.42% | 20.82 | 110.74 | |
| 3 | | | 2004 | 0.4532 | | 12.20% | | 5.53% | 21.69 | 113.00 | |
| 4 | | | 2005 | 0.4388 | | 11.80% | | 5.18% | 23.28 | 115.00 | |
| 5 | | | 2006 | 0.3514 | | 10.50% | | 3.69% | 24.32 | 117.00 | |
| 6 | | | GROWTH 2002 - 2006 | | | | | 5.02% | 2.50% | | 1.36% |
| 7 | | | 2007 | 0.3481 | | 10.50% | | 3.66% | | 117.00 | 0.00% |
| 8 | | | 2008 | 0.3724 | | 11.00% | | 4.10% | | 117.00 | 0.00% |
| 9 | | | 2010-12 | 0.3846 | | 11.00% | | 4.23% | 4.50% | 117.00 | 0.00% |
| 10 | | | | | | | | | | | |
| 11 | SO | SOUTHERN COMPANY | 2002 | 0.2649 | | 15.10% | | 4.00% | 12.15 | 716.90 | |
| 12 | | | 2003 | 0.2944 | | 14.80% | | 4.36% | 13.13 | 734.80 | |
| 13 | | | 2004 | 0.3107 | | 14.90% | | 4.63% | 13.86 | 741.80 | |
| 14 | | | 2005 | 0.3052 | | 14.90% | | 4.55% | 14.41 | 741.60 | |
| 15 | | | 2006 | 0.2667 | | 13.80% | | 3.68% | 15.23 | 746.60 | |
| 16 | | | GROWTH 2002 - 2006 | | | | | 4.24% | 1.00% | | 1.02% |
| 17 | | | 2007 | 0.2727 | | 13.50% | | 3.68% | | 765.00 | 2.46% |
| 18 | | | 2008 | 0.2783 | | 13.00% | | 3.62% | | 783.00 | 2.41% |
| 19 | | | 2010-12 | 0.2600 | | 13.00% | | 3.38% | 5.00% | 805.00 | 1.52% |
| 20 | | | | | | | | | | | |
| 21 | TE | TECO ENERGY, INC. | 2002 | 0.2769 | | 9.90% | | 2.74% | 14.86 | 175.80 | |
| 22 | | | 2003 | 0.1389 | | NMF | | NMF | 8.93 | 187.80 | |
| 23 | | | 2004 | -0.0704 | | 10.70% | | NMF | 6.43 | 199.70 | |
| 24 | | | 2005 | 0.2400 | | 13.30% | | 3.19% | 7.65 | 208.20 | |
| 25 | | | 2006 | 0.3504 | | 14.10% | | 4.94% | 8.25 | 209.50 | |
| 26 | | | GROWTH 2002 - 2006 | | | | | 3.62% | -9.50% | | 4.48% |
| 27 | | | 2007 | 0.4222 | | 15.00% | | 6.33% | | 210.50 | 0.48% |
| 28 | | | 2008 | 0.3043 | | 12.50% | | 3.80% | | 211.50 | 0.48% |
| 29 | | | 2010-12 | 0.3120 | | 11.50% | | 3.59% | 6.50% | 215.00 | 0.52% |
| 30 | | | | | | | | | | | |
| 31 | UIL | UIL HOLDINGS | 2002 | 0.0649 | | 9.10% | | 0.59% | 20.28 | 23.79 | |
| 32 | | | 2003 | -0.3952 | | 6.00% | | NMF | 20.65 | 23.86 | |
| 33 | | | 2004 | -0.1234 | | 6.70% | | NMF | 22.84 | 24.01 | |
| 34 | | | 2005 | -0.3308 | | 5.80% | | NMF | 22.39 | 24.32 | |
| 35 | | | 2006 | 0.0699 | | 9.90% | | 0.69% | 18.53 | 24.86 | |
| 36 | | | GROWTH 2002 - 2006 | | | | | 0.64% | 1.00% | | 1.11% |
| 37 | | | 2007 | 0.0649 | | 9.50% | | 0.62% | | 25.20 | 1.37% |
| 38 | | | 2008 | 0.1128 | | 10.00% | | 1.13% | | 25.40 | 1.08% |
| 39 | | | 2010-12 | 0.1953 | | 10.50% | | 2.05% | -1.00% | 26.60 | 1.36% |

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS



| LINE NO. | STOCK SYMBOL | LOCAL DISTRIBUTION COMPANY NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | VVC | VECTREN | 2002 | 0.3631 | | 13.10% | | 4.76% | 12.79 | 68.01 | |
| 2 | | | 2003 | 0.2885 | | 10.40% | | 3.00% | 14.18 | 75.60 | |
| 3 | | | 2004 | 0.1901 | | 9.90% | | 1.88% | 14.42 | 75.90 | |
| 4 | | | 2005 | 0.3425 | | 12.00% | | 4.11% | 15.01 | 76.19 | |
| 5 | | | 2006 | 0.1458 | | 9.30% | | 1.36% | 15.43 | 76.10 | |
| 6 | | | GROWTH 2002 - 2006 | | | | | 3.02% | 4.50% | | 2.85% |
| 7 | | | 2007 | 0.3135 | | 11.00% | | 3.45% | | 80.80 | 6.18% |
| 8 | | | 2008 | 0.3282 | | 11.00% | | 3.61% | | 81.00 | 3.17% |
| 9 | | | 2010-12 | 0.3024 | | 10.50% | | 3.18% | 4.50% | 81.60 | 1.41% |
| 10 | | | | | | | | | | | |
| 11 | XEL | XCEL ENERGY INC. | 2002 | -1.6905 | | 3.70% | | NMF | 11.70 | 398.71 | |
| 12 | | | 2003 | 0.3902 | | 9.80% | | 3.82% | 12.95 | 398.96 | |
| 13 | | | 2004 | 0.3622 | | 10.00% | | 3.62% | 12.99 | 400.46 | |
| 14 | | | 2005 | 0.2917 | | 9.20% | | 2.68% | 13.37 | 403.39 | |
| 15 | | | 2006 | 0.3481 | | 9.70% | | 3.38% | 14.28 | 407.30 | |
| 16 | | | GROWTH 2002 - 2006 | | | | | 3.38% | -4.50% | | 0.53% |
| 17 | | | 2007 | 0.3259 | | 9.00% | | 2.93% | | 427.00 | 4.84% |
| 18 | | | 2008 | 0.3667 | | 10.00% | | 3.67% | | 429.00 | 2.63% |
| 19 | | | 2010-12 | 0.3714 | | 10.00% | | 3.71% | 0.40% | 435.00 | 1.32% |

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
GROWTH RATE COMPARISON

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 6

| LINE NO. | STOCK SYMBOL | | (A) (br) + (sv) | (B) ZACKS EPS | (C) VALUE LINE PROJECTED EPS | (C) VALUE LINE PROJECTED DPS | (C) VALUE LINE PROJECTED BVPS | (D) VALUE LINE HISTORIC EPS | (D) VALUE LINE HISTORIC DPS | (D) VALUE LINE HISTORIC BVPS | (E) VALUE LINE & ZACKS AVGS. | (F) 5 - YEAR COMPOUND HISTORY EPS | (F) 5 - YEAR COMPOUND HISTORY DPS | (F) 5 - YEAR COMPOUND HISTORY BVPS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALE | ALLETTE, INC. | 5.45% | 5.00% | 8.00% | NMF | 5.50% | - | - | - | 6.17% | - | - | - |
| 2 | LNT | ALLIANT ENERGY | 5.25% | 6.00% | 5.50% | 8.00% | 4.00% | -3.00% | -11.50% | -2.50% | 0.93% | 14.95% | -12.92% | 3.51% |
| 3 | AEE | AMEREN CORP. | 2.52% | 6.20% | 3.00% | NMF | 3.00% | -2.00% | - | 5.50% | 3.14% | 0.00% | 0.00% | 6.32% |
| 4 | AEP | AMERICAN ELECTRIC POWER COMPANY, INC. | 6.03% | 5.40% | 6.50% | 7.50% | 6.00% | 3.00% | -9.50% | -2.50% | 2.34% | 0.00% | -11.09% | 3.29% |
| 5 | CHG | CH ENERGY GROUP, INC. | 2.50% | - | 3.00% | 1.00% | 2.00% | -2.50% | - | 1.50% | 1.00% | 4.83% | 0.00% | 1.79% |
| 6 | CV | CENTRAL VERMONT PUBLIC SERVICE CORPORATION | 3.73% | - | 9.00% | NMF | 3.00% | -2.50% | 1.00% | 2.00% | 2.50% | 1.43% | 1.12% | 1.27% |
| 7 | CNL | CLECO CORPORATION | 4.48% | 9.50% | 6.50% | 6.50% | 6.50% | - | 1.00% | 5.50% | 5.92% | -2.74% | 0.00% | 6.64% |
| 8 | ED | CONSOLIDATED EDISON, INC. | 3.38% | 3.20% | 4.00% | 1.00% | 5.00% | -2.00% | 1.00% | 3.00% | 2.17% | -1.47% | 0.89% | 2.95% |
| 9 | DTE | DTE ENERGY COMPANY | 2.50% | 6.00% | 4.00% | 2.50% | 2.50% | -1.00% | - | 3.00% | 2.83% | -10.57% | 0.24% | 4.91% |
| 10 | EDE | EMPIRE DISTRICT ELECTRIC COMPANY | 3.97% | - | 8.50% | 1.00% | 3.00% | 1.00% | - | 2.00% | 3.10% | 4.33% | 0.00% | 1.51% |
| 11 | FE | FIRSTENERGY CORP. | 7.26% | 7.50% | 9.00% | 5.50% | 6.00% | 3.50% | 4.00% | 4.50% | 5.71% | 10.74% | 5.38% | 4.29% |
| 12 | HE | HAWAIIAN ELECTRIC INDUSTRIES, INC. | 2.41% | 4.50% | 1.50% | NMF | -0.50% | -1.00% | - | 2.00% | 1.30% | -4.81% | 0.00% | -1.38% |
| 13 | IDA | IDACORP, INC. | 3.63% | 5.00% | 2.00% | NMF | 4.00% | -8.50% | -8.50% | 2.50% | -0.58% | 9.58% | -10.38% | 2.86% |
| 14 | MGEE | MGE ENERGY, INC. | 7.05% | - | 6.00% | 0.50% | 7.00% | 2.50% | 1.00% | 7.00% | 4.00% | 5.07% | 0.92% | 8.43% |
| 15 | NI | NISOURCE, INC. | 2.00% | 2.80% | 2.50% | 1.50% | 2.00% | 0.50% | -1.50% | 4.00% | 1.69% | -12.10% | -5.63% | 2.22% |
| 16 | NST | NSTAR | 6.01% | 6.20% | 8.50% | 7.00% | 5.50% | 3.50% | 3.00% | 2.50% | 5.17% | 3.38% | 9.53% | 4.88% |
| 17 | PNM | PNM RESOURCES | 2.70% | 8.50% | 2.50% | 6.00% | 4.50% | -2.50% | 7.50% | 4.50% | 4.43% | 12.60% | 10.83% | 7.40% |
| 18 | PNW | PINNACLE WEST CAPITAL CORPORATION | 2.02% | 6.70% | 1.50% | 3.00% | 2.00% | -5.00% | 6.00% | 4.00% | 2.60% | 5.80% | 5.64% | 4.02% |
| 19 | PPL | PPL CORPORATION | 11.26% | 10.30% | 14.00% | 15.00% | 8.50% | 6.50% | 13.00% | 14.00% | 11.61% | 10.43% | 11.18% | 18.65% |
| 20 | PGN | PROGRESSS ENERGY | 2.33% | 5.20% | 3.50% | 1.00% | 1.50% | -0.50% | 2.50% | 5.00% | 2.60% | -14.52% | 2.65% | 3.03% |
| 21 | SCG | SCANA CORPORATION | 4.03% | 5.00% | 3.50% | 4.00% | 4.50% | 7.00% | 5.00% | 2.50% | 4.50% | 2.14% | 6.62% | 5.49% |
| 22 | SO | SOUTHERN COMPANY | 5.01% | 4.60% | 3.00% | 4.00% | 5.00% | 3.00% | 2.00% | 1.00% | 3.23% | 3.22% | 3.16% | 5.81% |
| 23 | TE | TECO ENERGY, INC. | 4.72% | 7.30% | 4.50% | 2.00% | 6.50% | -13.00% | -10.50% | -9.50% | -1.81% | -11.99% | -14.32% | -13.68% |
| 24 | UIL | UIL HOLDINGS | 2.56% | - | 5.50% | NMF | -1.00% | -8.50% | - | 1.00% | -0.75% | 0.13% | 0.00% | -2.23% |
| 25 | VVC | VECTREN | 4.81% | 4.70% | 4.50% | 3.00% | 4.50% | 4.50% | 4.00% | 4.50% | 4.24% | -3.78% | 3.55% | 4.80% |
| 26 | XEL | XCEL ENERGY INC. | 4.24% | 5.20% | 5.50% | 4.50% | 0.40% | -6.50% | -10.50% | -4.50% | -0.84% | 33.90% | -6.06% | 5.11% |
| 27 | | | | | 5.21% | 3.88% | 3.88% | -1.10% | -0.05% | 2.50% | | 2.42% | 0.05% | 3.68% |
| 28 | AVERAGES | | 4.30% | 5.94% | | 4.32% | | | 0.45% | | 2.97% | | 2.05% | |

REFERENCES:

COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007

**TUCSON ELECTRIC POWER COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2006**
**CAPM COST OF EQUITY CAPITAL**



BASED ON A GEOMETRIC MEAN:

| LINE NO. | STOCK SYMBOL | COMPANY NAME | k | = | $r_f$ | + [ | (A) ß | x ( | $r_m$ | - | $r_f$ | ) ] | = | (B) EXPECTED RETURN |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALE | ALLETTE, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 10.40% | - | 2.68% | ) ] | = | 10.01% |
| 2 | LNT | ALLIANT ENERGY | k | = | 2.68% | + [ | 0.80 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.86% |
| 3 | AEE | AMEREN CORP. | k | = | 2.68% | + [ | 0.80 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.86% |
| 4 | AEP | AMERICAN ELECTRIC POWER COMPANY, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 10.40% | - | 2.68% | ) ] | = | 10.01% |
| 5 | CHG | CH ENERGY GROUP, INC. | k | = | 2.68% | + [ | 0.90 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.63% |
| 6 | CV | CENTRAL VERMONT PUBLIC SERVICE CORPORATION | k | = | 2.68% | + [ | 1.00 | x ( | 10.40% | - | 2.68% | ) ] | = | 10.40% |
| 7 | CNL | CLECO CORPORATION | k | = | 2.68% | + [ | 1.15 | x ( | 10.40% | - | 2.68% | ) ] | = | 11.56% |
| 8 | ED | CONSOLIDATED EDISON, INC. | k | = | 2.68% | + [ | 0.75 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.47% |
| 9 | DTE | DTE ENERGY COMPANY | k | = | 2.68% | + [ | 0.80 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.86% |
| 10 | EDE | EMPIRE DISTRICT ELECTRIC COMPANY | k | = | 2.68% | + [ | 0.85 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.24% |
| 11 | FE | FIRSTENERGY CORP. | k | = | 2.68% | + [ | 0.85 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.24% |
| 12 | HE | HAWAIIAN ELECTRIC INDUSTRIES, INC. | k | = | 2.68% | + [ | 0.75 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.47% |
| 13 | IDA | IDACORP, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 10.40% | - | 2.68% | ) ] | = | 10.01% |
| 14 | MGEE | MGE ENERGY, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 10.40% | - | 2.68% | ) ] | = | 10.01% |
| 15 | NI | NISOURCE, INC. | k | = | 2.68% | + [ | 0.90 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.63% |
| 16 | NST | NSTAR | k | = | 2.68% | + [ | 0.75 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.47% |
| 17 | PNM | PNM RESOURCES | k | = | 2.68% | + [ | 0.90 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.63% |
| 18 | PNW | PINNACLE WEST CAPITAL CORPORATION | k | = | 2.68% | + [ | 0.80 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.86% |
| 19 | PPL | PPL CORPORATION | k | = | 2.68% | + [ | 0.90 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.63% |
| 20 | PGN | PROGRESSS ENERGY | k | = | 2.68% | + [ | 0.85 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.24% |
| 21 | SCG | SCANA CORPORATION | k | = | 2.68% | + [ | 0.85 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.24% |
| 22 | SO | SOUTHERN COMPANY | k | = | 2.68% | + [ | 0.70 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.08% |
| 23 | TE | TECO ENERGY, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 10.40% | - | 2.68% | ) ] | = | 10.01% |
| 24 | UIL | UIL HOLDINGS | k | = | 2.68% | + [ | 0.95 | x ( | 10.40% | - | 2.68% | ) ] | = | 10.01% |
| 25 | VVC | VECTREN | k | = | 2.68% | + [ | 0.90 | x ( | 10.40% | - | 2.68% | ) ] | = | 9.63% |
| 26 | XEL | XCEL ENERGY INC. | k | = | 2.68% | + [ | 0.80 | x ( | 10.40% | - | 2.68% | ) ] | = | 8.86% |
| 27 | **AVERAGE** | | | | | | 0.87 | | | | | | | 9.42% |

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [\,ß\,(r_m - r_f)\,]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
$r_f$ = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
$r_m$ = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 01/11/2008 THROUGH 02/15/2008 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE GEOMETRIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK .

BASED ON AN ARITHMETIC MEAN:

| LINE NO. | STOCK SYMBOL | COMPANY NAME | k | = | $r_f$ | + [ | (A) ß | x ( | $r_m$ | - | $r_f$ | ) ] | = | (B) EXPECTED RETURN |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALE | ALLETTE, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.82% |
| 2 | LNT | ALLIANT ENERGY | k | = | 2.68% | + [ | 0.80 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.38% |
| 3 | AEE | AMEREN CORP. | k | = | 2.68% | + [ | 0.80 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.38% |
| 4 | AEP | AMERICAN ELECTRIC POWER COMPANY, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.82% |
| 5 | CHG | CH ENERGY GROUP, INC. | k | = | 2.68% | + [ | 0.90 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.34% |
| 6 | CV | CENTRAL VERMONT PUBLIC SERVICE CORPORATION | k | = | 2.68% | + [ | 1.00 | x ( | 12.30% | - | 2.68% | ) ] | = | 12.30% |
| 7 | CNL | CLECO CORPORATION | k | = | 2.68% | + [ | 1.15 | x ( | 12.30% | - | 2.68% | ) ] | = | 13.74% |
| 8 | ED | CONSOLIDATED EDISON, INC. | k | = | 2.68% | + [ | 0.75 | x ( | 12.30% | - | 2.68% | ) ] | = | 9.89% |
| 9 | DTE | DTE ENERGY COMPANY | k | = | 2.68% | + [ | 0.80 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.38% |
| 10 | EDE | EMPIRE DISTRICT ELECTRIC COMPANY | k | = | 2.68% | + [ | 0.85 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.86% |
| 11 | FE | FIRSTENERGY CORP. | k | = | 2.68% | + [ | 0.85 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.86% |
| 12 | HE | HAWAIIAN ELECTRIC INDUSTRIES, INC. | k | = | 2.68% | + [ | 0.75 | x ( | 12.30% | - | 2.68% | ) ] | = | 9.89% |
| 13 | IDA | IDACORP, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.82% |
| 14 | MGEE | MGE ENERGY, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.82% |
| 15 | NI | NISOURCE, INC. | k | = | 2.68% | + [ | 0.90 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.34% |
| 16 | NST | NSTAR | k | = | 2.68% | + [ | 0.75 | x ( | 12.30% | - | 2.68% | ) ] | = | 9.89% |
| 17 | PNM | PNM RESOURCES | k | = | 2.68% | + [ | 0.90 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.34% |
| 18 | PNW | PINNACLE WEST CAPITAL CORPORATION | k | = | 2.68% | + [ | 0.80 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.38% |
| 19 | PPL | PPL CORPORATION | k | = | 2.68% | + [ | 0.90 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.34% |
| 20 | PGN | PROGRESSS ENERGY | k | = | 2.68% | + [ | 0.85 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.86% |
| 21 | SCG | SCANA CORPORATION | k | = | 2.68% | + [ | 0.85 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.86% |
| 22 | SO | SOUTHERN COMPANY | k | = | 2.68% | + [ | 0.70 | x ( | 12.30% | - | 2.68% | ) ] | = | 9.41% |
| 23 | TE | TECO ENERGY, INC. | k | = | 2.68% | + [ | 0.95 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.82% |
| 24 | UIL | UIL HOLDINGS | k | = | 2.68% | + [ | 0.95 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.82% |
| 25 | VVC | VECTREN | k | = | 2.68% | + [ | 0.90 | x ( | 12.30% | - | 2.68% | ) ] | = | 11.34% |
| 26 | XEL | XCEL ENERGY INC. | k | = | 2.68% | + [ | 0.80 | x ( | 12.30% | - | 2.68% | ) ] | = | 10.38% |
| 27 | **AVERAGE** | | | | | | 0.87 | | | | | | | 11.08% |

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [ ß ( r_m - r_f ) ]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
$r_f$ = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
$r_m$ = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 01/11/2008 THROUGH 02/15/2008 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK.

**TUCSON ELECTRIC POWER COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2006**
**ECONOMIC INDICATORS - 1990 TO PRESENT**

**DOCKET NO. E-01933A-07-0402**
**SCHEDULE WAR - 8**

| LINE NO. | YEAR | (A) CHANGE IN CPI | (B) CHANGE IN GDP (1996 $) | (C) PRIME RATE | (D) FED. DISC. RATE | (E) FED. FUNDS RATE | (F) 91-DAY T-BILLS | (G) 30-YR T-BONDS | (H) A-RATED UTIL. BOND YIELD | (I) Baa-RATED UTIL. BOND YIELD |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1990 | 5.40% | 1.90% | 10.01% | 6.98% | 8.10% | 7.50% | 7.49% | 9.86% | 10.06% |
| 2 | 1991 | 4.21% | -0.20% | 8.46% | 5.45% | 5.69% | 5.38% | 5.38% | 9.36% | 9.55% |
| 3 | 1992 | 3.01% | 3.30% | 6.25% | 3.25% | 3.52% | 3.43% | 3.43% | 8.69% | 8.86% |
| 4 | 1993 | 2.99% | 2.70% | 6.00% | 3.00% | 3.02% | 3.00% | 3.00% | 7.59% | 7.91% |
| 5 | 1994 | 2.56% | 4.00% | 7.14% | 3.60% | 4.21% | 4.25% | 4.25% | 8.31% | 8.63% |
| 6 | 1995 | 2.83% | 2.50% | 8.83% | 5.21% | 5.83% | 5.49% | 5.49% | 7.89% | 8.29% |
| 7 | 1996 | 2.95% | 3.70% | 8.27% | 5.02% | 5.30% | 5.01% | 5.01% | 7.75% | 8.17% |
| 8 | 1997 | 1.70% | 4.50% | 8.44% | 5.00% | 5.46% | 5.06% | 5.06% | 7.60% | 8.12% |
| 9 | 1998 | 1.60% | 4.20% | 8.35% | 4.92% | 5.35% | 4.78% | 4.78% | 7.04% | 7.27% |
| 10 | 1999 | 2.70% | 4.50% | 7.99% | 4.62% | 4.97% | 4.64% | 4.64% | 7.62% | 7.88% |
| 11 | 2000 | 3.40% | 3.70% | 9.23% | 5.73% | 6.24% | 5.82% | 5.82% | 8.24% | 8.36% |
| 12 | 2001 | 1.60% | 0.80% | 6.92% | 3.41% | 3.88% | 3.40% | 5.95% | 7.59% | 8.02% |
| 13 | 2002 | 2.40% | 1.60% | 4.67% | 1.17% | 1.67% | 1.61% | 5.38% | 7.41% | 7.98% |
| 14 | 2003 | 1.90% | 2.50% | 4.12% | 2.03% | 1.13% | 1.01% | 4.92% | 6.18% | 6.64% |
| 15 | 2004 | 3.30% | 3.90% | 4.34% | 2.34% | 1.35% | 1.37% | 5.03% | 5.77% | 6.20% |
| 16 | 2005 | 3.40% | 3.20% | 6.16% | 4.19% | 3.22% | 3.15% | 4.57% | 5.38% | 5.78% |
| 17 | 2006 | 2.50% | 3.30% | 7.97% | 5.96% | 4.97% | 4.73% | 4.91% | 5.94% | 6.30% |
| 18 | 2007 | 4.10% | 2.20% | 8.05% | 5.86% | 5.02% | 4.36% | 4.84% | 6.07% | 6.24% |
| 19 | CURRENT | 4.10% | 2.20% | 6.00% | 3.50% | 3.00% | 2.09% | 4.36% | 6.02% | 6.20% |

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (F): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 02/15/2008
COLUMN (G) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 02/15/2008
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. E-01933A-07-04
SCHEDULE WAR - 9

| | ALE | PCT. | LNT | PCT. | AEE | PCT. | AEP | PCT. |
|---|---|---|---|---|---|---|---|---|
| DEBT | $ 359.8 | 35.1% | $ 2,651.3 | 62.9% | $ 5,285.0 | 44.5% | $ 12,429.0 | 56.7% |
| PREFERRED STOCK | 0.0 | 0.0% | 243.8 | 5.8% | 18.0 | 0.2% | 61.0 | 0.3% |
| COMMON EQUITY | 665.8 | 64.9% | 1,323.3 | 31.4% | 6,583.0 | 55.4% | 9,412.0 | 43.0% |
| TOTALS | $ 1,025.6 | 100% | $ 4,218.4 | 100% | $ 11,886.0 | 100% | $ 21,902.0 | 100% |

| | CHG | NST | CV | PCT. | CNL | PCT. | ED | PCT. |
|---|---|---|---|---|---|---|---|---|
| DEBT | $ 337,889.0 | 38.8% | $ 123.0 | 39.2% | $ 619,341.0 | 40.9% | $ 8,298.0 | 50.2% |
| PREFERRED STOCK | 21,027.0 | 2.4% | 12.0 | 3.8% | 20,092.0 | 1.3% | 213.0 | 1.3% |
| COMMON EQUITY | 512,862.0 | 58.8% | 179.0 | 57.0% | 876,129.0 | 57.8% | 8,004.0 | 48.5% |
| TOTALS | $ 871,778.0 | 100% | $ 314.0 | 100% | $ 1,515,562.0 | 100% | $ 16,515.0 | 100% |

| | DTE | NST | EDE | PCT. | FE | PCT. | HE | PCT. |
|---|---|---|---|---|---|---|---|---|
| DEBT | $ 7,474.0 | 56.1% | $ 462,437.0 | 49.7% | $ 8,535.0 | 48.6% | $ 1,133,185.0 | 50.9% |
| PREFERRED STOCK | 0.0 | 0.0% | 0.0 | 0.0% | 0.0 | 0.0% | 0.0 | 0.0% |
| COMMON EQUITY | 5,849.0 | 43.9% | 468,609.0 | 50.3% | 9,035.0 | 51.4% | 1,095,240.0 | 49.1% |
| TOTALS | $ 13,323.0 | 100% | $ 931,046.0 | 100% | $ 17,570.0 | 100% | $ 2,228,425.0 | 100% |

| | IDA | PCT. | MGEE | PCT. | NI | PCT. | NST | PCT. |
|---|---|---|---|---|---|---|---|---|
| DEBT | $ 928,648.0 | 45.2% | $ 237,284.0 | 38.7% | $ 5,146.2 | 50.7% | $ 2,444,774.0 | 60.1% |
| PREFERRED STOCK | 0.0 | 0.0% | 0.0 | 0.0% | 0.0 | 0.0% | 43,000.0 | 1.1% |
| COMMON EQUITY | 1,124,183.0 | 54.8% | 375,348.0 | 61.3% | 5,013.6 | 49.3% | 1,582,563.0 | 38.9% |
| TOTALS | $ 2,052,831.0 | 100% | $ 612,632.0 | 100% | $ 10,159.8 | 100% | $ 4,070,337.0 | 100% |

| | PNM | PCT. | PNW | PCT. | PPL | PCT. | PGN | PCT. |
|---|---|---|---|---|---|---|---|---|
| DEBT | $ 1,765,907.0 | 50.9% | $ 3,232,633.0 | 48.4% | $ 6,728.0 | 55.4% | $ 8,845.0 | 51.4% |
| PREFERRED STOCK | 11,529.0 | 0.3% | 0.0 | 0.0% | 301.0 | 2.5% | 93.0 | 0.5% |
| COMMON EQUITY | 1,693,296.0 | 48.8% | 3,446,116.0 | 51.6% | 5,122.0 | 42.2% | 8,286.0 | 48.1% |
| TOTALS | $ 3,470,732.0 | 100% | $ 6,678,749.0 | 100% | $ 12,151.0 | 100% | $ 17,224.0 | 100% |

| | SCG | PCT. | SO | PCT. | TE | PCT. | UIL | PCT. |
|---|---|---|---|---|---|---|---|---|
| DEBT | $ 3,067.0 | 50.9% | $ 12,503.0 | 50.8% | $ 3,212.6 | 65.0% | $ 408,603.0 | 47.0% |
| PREFERRED STOCK | 114.0 | 1.9% | 744.0 | 3.0% | 0.0 | 0.0% | 0.0 | 0.0% |
| COMMON EQUITY | 2,846.0 | 47.2% | 11,371.0 | 46.2% | 1,729.0 | 35.0% | 460,581.0 | 53.0% |
| TOTALS | $ 6,027.0 | 100% | $ 24,618.0 | 100% | $ 4,941.6 | 100% | $ 869,184.0 | 100% |

| | VVC | PCT. | VVC | PCT. | ELECTRIC COMPANY SAMPLE AVERAGE | PCT. | UNS | PCT. |
|---|---|---|---|---|---|---|---|---|
| DEBT | $ 1,208.0 | 50.7% | $ 1,208.0 | 50.7% | $ 448,375.9 | 49.7% | $ 1,759,941.0 | 72.9% |
| PREFERRED STOCK | 0.0 | 0.0% | 0.0 | 0.0% | 3,748.0 | 0.4% | 0.0 | 0.0% |
| COMMON EQUITY | 1,174.2 | 49.3% | 1,174.2 | 49.3% | 450,488.2 | 49.9% | 654,149.0 | 27.1% |
| TOTALS | $ 2,382.2 | 100% | $ 2,382.2 | 100% | $ 902,612.1 | 100% | $ 2,414,090.0 | 100% |

REFERENCE:
MOST RECENT SEC 10(k) FILINGS OR COMPANY ANNUAL REPORTS

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

DIRECT TESTIMONY

OF

BEN JOHNSON, PH.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 29, 2008

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TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. E-01933A-07-0402

Docket No. E-01933A-05-0650

## Introduction

**Q. Would you please state your name and address?**

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

**Q. What is your present occupation?**

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

**Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?**

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

**Q. What is your purpose in making your appearance at this hearing?**

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with

RUCO's evaluation of the three methodologies proposed by Tuscon Electric Power Company (TEP) for setting rates related to generating electricity.

Following this introduction, my testimony has four sections. In the first section, I briefly summarize some of the history leading to this proceeding. In the second section, I summarize the three rate setting methodologies proposed by TEP, focusing on the development of rates for generation services. In the third section, I discuss several problems with TEP's filing. In this section I point out how TEP's forecasted rates are flawed, and could lead the Commission to the wrong conclusion when evaluating the merits of TEP's proposed rate-setting methodologies. I also discuss how market-based generation rates may result in rates that are not just and reasonable – a problem that also applies to TEP's hybrid proposal. In the fourth and final section, I summarize my conclusions and recommendations.

**Q. As background information, can you please briefly summarize the history of this Commission's Electric Competition rules?**

A. The Commission adopted its Electric Competition Rules (Rules) in 1996. [See, Decision No. 59943] The Rules were intended to "set forth a framework for the inevitable transition from a non-competitive to a competitive environment". [Id., p. 2]

Among other things, the Rules required TEP to file estimates of its stranded costs, and required commission approval of any charges intended to recover stranded costs. [R14-2-1607(G) and (H)] In September 1999, the Commission revised the Rules to require TEP to divest its generation assets and to purchase its power for Standard Offer Service from the competitive market. [R14-2-1615(A) and R14-2-1606(B)] The Rules also declare that rates set by the market for competitive services are deemed just and reasonable. [R14-2-1611(A)]

**Q. Now, can you briefly summarize this Commission's efforts to foster competition as they relate specifically to Tucson Electric Power?**

A. On June 22, 1998 the Commission issued it's Stranded Cost Order, which required TEP to file a plan for stranded cost recovery. [Decision No. 60977] On August 10, 1998, TEP filed its Stranded Cost Recovery Plan. On June 9, 1999, TEP, RUCO and several other parties entered into Settlement Proposal, which was intended to resolve various disputed issues concerning TEP's proposed Stranded Cost Recovery Plan. [See, Decision 62103, p. 2] On November 30, 1999, the Commission adopted the Settlement Agreement, with modifications. [Decision 62103]

The Settlement Agreement required TEP to transfer its generation assets to a subsidiary by December 31, 2002. [Settlement Agreement § 3.1] The Settlement Agreement also reaffirmed rate reductions of 1 percent in 1999 and again in 2000, and a rate freeze thereafter through December 31, 2008. [Settlement Agreement § 5.1] In exchange, the Settlement Agreement provided mechanisms for the recovery of TEP's stranded costs, thereby shielding TEP from the anticipated adverse financial impact of allowing competitors to supply electricity in TEP's service area.

**Q. Can you explain how TEP's stranded costs were to be recovered under the Settlement Agreement?**

A. Yes. TEP's frozen rates would include a fixed Competitive Transition Charge (CTC) and a floating CTC. [Settlement Agreement § 2.1] The fixed CTC was set at 0.93 cents/kWh and would terminate after recovery of $450 million of stranded costs, or on December 31, 2008, whichever occurred first. [Id.] The floating CTC was intended to recover an estimated additional $233 million in stranded costs. The floating CTC would be determined in part by a Market Generation Credit (MGC) based upon a market-index futures price. The MGC and CTC were inversely related; an increase in the MGC results in a decrease in the CTC, and vice versa.

In other words, the floating CTC would decrease as the market price of power increased (as estimated by the MGC market index). The Settlement Agreement acknowledged that the floating CTC could actually be negative, if short term wholesale prices increase, in which case "the negative value would be credited to the customers' monthly bill". [Decision 62103, p. 5] The Settlement Agreement provides for termination of the floating CTC on December 31, 2008. [Id.]

**Q. Are there any other major provisions of the Settlement Agreement that you would like to mention at this point?**

A. Yes. The Settlement Agreement also provided for a review of TEP's rates in 2004. The purpose was to facilitate a Commission investigation into whether TEP's Standard Offer rates, or its overall unbundled rates had been set too high, and should be reduced. [Settlement Agreement, § 5.2]

**Q. Can you now discuss the next significant event leading up to this proceeding?**

A. On September 10, 2002 the Commission issued its "Track A Order", which modified portions of the Rules and Decision 62103. [Decision No. 65154] Specifically, the Track A Order granted TEP a waiver from the requirement to divest its generation assets and the requirement to purchase energy on the competitive market. [Id., pp. 32-33] The Commission stated:

> In retrospect, it was a good idea to delay divestiture and competitive procurement in the APS and TEP Settlement Agreements, given what has happened in the last two or so years, including the experience in California; the market volatility and illiquidity; and the lack of public confidence in the transition to electric deregulation and ability of regulators to prevent price spikes, ensure reliable service, and prevent bankruptcies. Even today, there is not agreement amongst economists, much less regulators, as to why ...what happened in California, happened, and how to prevent a similar or related occurrence.
>
> It is clear that the Commission and all parties expected benefits from retail competition, yet there is no active retail Competition, so actual benefits are still unknown. It is said that consumers will benefit from wholesale competition, but not without the proper market structure and regulatory framework that will support it. It was anticipated that at the time that APS and

> TEP divested, ESPs would be providing direct access to retail customers. In actuality, no retail competition exists; market power is held by the incumbent utilities; no RTO is in effect; transmission constraints exist that potentially exacerbate market abuse; the GAO has issued a negative report on FERC's ability to manage competitive markets; both TEP and APS recognize a problem - one wants to postpone its divestiture while the other is affected by its parent's and affiliates' adverse financial considerations; proposed new generation may be cancelled if it is not able to find a market; more protections are needed against self-dealing and inappropriate affiliate transactions; and investigations are ongoing into market manipulations and improprieties. Contrary to what APS argues, these changes relate to the question of divestiture, especially to our willingness to transfer our ratemaking jurisdiction over generation assets to FERC, given its recent history regulating the wholesale market and the conclusions contained in the recent GAO report. [Id., p. 22]

**Q. Have the Commission's Competition Rules also been the subject of some controversy?**

A. Yes. Various parties challenged the Rules, and several Certificates of Convenience and Necessity (CC&Ns) that were issued to potential competitors pursuant to the Rules. Primarily at issue was Rule R14-2-1611 which provides: "Market determined rates for Competitive Services, as defined in R14-2-1601 shall be deemed to be just and reasonable."

In resolving this dispute, the Court of Appeals of Arizona noted that the Arizona Constitution requires the Commission to "prescribe ... just and reasonable rates and charges to be made and collected by public service corporations" and to "ascertain the fair value of the property within the State of every public service corporation doing business therein." [Phelps Dodge v. AEPCO, 83 P.3d 573, ¶ 18 (App. 2004)] The Court of Appeals concluded that the Commission violated these portions of the Arizona Constitution by approving CC&N's for competitive electric providers without first determining and considering fair value. [Id., ¶ 24] As well, the Court rejected the Commission's sweeping replacement of traditional ratemaking principles with market-based pricing, concluding that "the Commission may not abdicate its constitutional responsibility to set just and reasonable rates by allowing competitive market forces alone to do so". [Id., ¶ 32]

**Q. Previously you mentioned that TEP's rates were supposed to be reviewed in 2004. Did that review occur?**

A. Yes. In 2004 TEP filed the rate review required by Decision No. 62103, claiming a revenue deficiency of $111 million. The Staff, RUCO and other parties disputed TEP's alleged revenue deficiency, contending that this computation was greatly overstated. However, no party concluded that TEP was over-earning, which was the key issue under consideration. Hence, the proceeding was suspended and no action was taken by the Commission.

**Q. What happened after the 2004 rate review?**

A. In 2005, TEP filed a Motion for Declaratory Order, seeking clarification of whether TEP would be entitled to charge Standard Offer generation rates based on the MGC in 2009 and beyond. After several parties filed opposition to the Motion for Declaratory Order, the Administrative Law Judge issued a procedural order suggesting TEP file its request for relief in a different form. TEP then filed a Motion to Amend Decision No. 62103. That Motion was assigned Docket No. E-01933A-05-0650. In April 2006, the Commission issued Decision No. 68669, which ordered that a hearing be held to consider amending Decision No. 62103 and the Settlement Agreement. TEP then filed testimony in which it claimed that the Settlement Agreement provided that TEP could begin charging market-based rates beginning in 2009 in accordance with the MGC provisions of the Settlement Agreement. TEP's testimony also presented two proposals for generation rates beginning in 2009, a market-phase in proposal and a traditional cost of service proposal that included an $850 million regulatory asset.

**Q. What was RUCO's position on TEP's Motion to Amend Decision No. 62103?**

A. RUCO opposed TEP's claim that the Settlement Agreement required the use of the MGC mechanism to establish Standard Offer generation rates in 2009. RUCO also opposed the two alternatives TEP had proposed, and suggested that the Commission should establish rates based on a traditional cost of service rate case, to be effective in 2009. RUCO filed testimony and a legal memorandum in support of its position[1]. Other parties likewise disagreed with TEP's contention that generation rates for Standard Offer service would be based on the MGC in 2009. During the hearing on the Motion to Amend in March 2007, TEP offered another alternative for setting generation rates based on a hybrid of cost-based and market-based rates.

**Q. What was the disposition of TEP's Motion to Amend?**

A. The Commission issued Decision No. 69568 in May 2007. The Commission did not decide the issue of how rates would be established in 2009, but ordered TEP to file a rate application that included all of its rate proposals for side-by-side comparison. The Commission ordered that the rate application would be consolidated with the docket on the Motion to Amend. In July 2007, TEP filed the rate application that is the subject of my testimony.

**Q. How does your testimony differ from that RUCO offered in response to the Motion to Amend?**

A. The testimony and legal memorandum RUCO presented in the Motion to Amend docket explained why the Commission was not required to establish TEP's rates based on the MGC methodology beginning in 2009. My testimony is meant to evaluate the relative merits of TEP's various proposals based on the assumption that the Commission agrees it is not required to use the MGC methodology as TEP has claimed it is.

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1 Direct Testimony of Marylee Diaz Cortez, filed January 7, 2007 in Docket No. E-0933A-05-0650 (with attached legal memorandum); and Surrebuttal Testimony of Marylee Diaz Cortez, filed February 8, 2007 in the same docket. Ms. Diaz Cortez also testified at the hearing in March 2007. The entire record in Docket No. E-01933A-05-0650 has been consolidated with the Rate Application, per Decision No. 69568.

**TEP's Generation Proposals**

**Q. Could you now summarize TEP's proposals regarding the treatment of generation assets and its proposals for rates related to generating electricity?**

A. TEP proposes three different rate making methodologies, which differ in their treatment of TEP's generating plants, and in the development of rates related to generation. The methods are: the "Market Methodology", the "Cost-of-Service Methodology", and the "Hybrid Methodology".

**Q. Can you briefly describe TEP's proposed Market Methodology?**

A. Yes. TEP claims that, beginning January 1, 2009, it is entitled to charge market-based rates for generation service.[2]

> TEP has presented the Market Methodology to the Commission because it believes that when the rate increase moratorium in the 1999 Settlement Agreement is lifted on January 1, 2009, it is entitled to (i) a rate increase for transmission and distribution service; and (ii) charge rates for generation service based upon the market-based methodology set forth in the 1999 Settlement Agreement. [Pignatelli Direct Testimony, p. ii]

The Market Methodology put forward by TEP is premised on this interpretation of the 1999 Settlement Agreement. TEP seems to be claiming it has a legal right to charge customers for generation based on a "market-based proxy, the Market Generation Credit ("MGC")" as set forth in the 1999 Settlement Agreement". TEP's support for its Market proposal is based almost entirely on its legal theory and its claims concerning the 1999 Settlement Agreement. In its direct case, TEP made no real effort to demonstrate that its Market proposal is in the public interest, treats customers fairly, or results in fair and reasonable rates.

While TEP claims it is entitled to charge market-based rates consistent with its Market proposal, it does provide two alternatives for Commission consideration. The Cost-of-Service

2 As discussed above, RUCO disagrees with TEP's position and has set forth the basis for that disagreement in Docket No. E-01933A-05-0650.

and Hybrid Methodologies are presented to "help the Commission evaluate our proposals for amending the 1999 Settlement Agreement and Decision No. 62103 in furtherance of settlement discussions and negotiations among the parties to the 1999 Settlement Agreement". [Id., p. 7]

**Q. How would rates for transmission and distribution services be developed under the Market Methodology?**

A. Transmission and distribution rates would be based on a traditional cost of service approach recovering TEP's actual costs and allowing it to earn a fair return on the transmission and distribution portion of its fair value rate base. [See, Id., p. i]

**Q. Can you now explain how rates for generation service would be determined under the Market Methodology?**

A. Under the Market Methodology, TEP proposes to set prices for generation service using the MGC computations set forth in its Settlement Agreement.

> Market prices for generation service would be calculated using the existing Market Generation Credit ("MGC") rate schedule (Rate Schedule MGC-1) from TEP's 1999 Settlement Agreement as modified by Decision No. 65754 (March 20, 2003). This Schedule is attached to my testimony as Exhibit DGH-11, and incorporated herein. This MGC value is derived from a Palo Verde market index published by Platts, a McGraw-Hill publication. [Hutchins Direst Testimony, p. 47]

The Settlement Agreement provides that the MGC is calculated 30 days prior to each calendar estimation month using the most recent 3 day average of the Platts Long-Term Forward Assessment for Palo Verde Forward prices. [See, Schedule MGC-1, p. 2] These are "spot" prices for large blocks of electricity transferred from one utility to another on a short term basis.

**Q. Are there any other aspects of the Market Methodology you would like to mention at this point?**

A. Yes. There is one other point I would like to mention. Under the Market Methodology, TEP's rate base would include an Implementation Cost Regulatory Asset (ICRA) of $14.2 million to recover "direct costs incurred to implement competition in compliance with the 1999 Settlement Agreement". [Id., p. 5] The largest component of the $14.2 million ICRA is computer software costs. [Kissinger Direct Testimony, p. 8] The $14.2 million ICRA also includes costs incurred by funding and developing two entities (Desert Star and WestConnect) which were formed to provide more open access to the Arizona transmission grid. [Id., p. 10] Other costs include consulting fees, and accounting, legal, administrative, and payroll expenses. [Id., pp. 8-10]

**Q. What is the rate impact of TEP's proposed Market Methodology?**

A. By the Company's calculations, the Market Methodology would result in an immediate 21.9% increase "based on current projections for wholesale market power prices". [TEP Application, p. 2]

**Q. Can you now summarize TEP's proposed Cost-of-Service Methodology?**

A. If the Commission rejects the Market Methodology (e.g. because it would result in unreasonably high rates), TEP nevertheless wants a rate increase of a similar magnitude. It proposes to accomplish this by implementing a modified version of traditional rate making. Nominally, transmission, distribution and generation rates would all be based on cost of service principles. [Id.] Significantly, however, TEP proposes to include both a $47.5 Million ICRA in its rate base, and to recover an additional $788 million which it refers to as a Termination Cost Regulatory Asset (TCRA) [Id., p. 7]. The effect of the proposed TCRA, if approved, would be to increase rates to nearly the same level as its Market proposal.

**Q. What is included in the $47.5 million ICRA?**

A. The $47.5 million ICRA includes the $14.2 million discussed previously, plus additional costs that TEP incurred in buying out certain coal contracts, and refinancing costs associated with certain generation assets. [Id., pp. 11-12]

**Q. Can you now explain the $788 million TCRA?**

A. TEP claims that the TCRA reflects it's estimate of the "financial impact of meeting its obligations under the 1999 Settlement Agreement and transitioning back to cost-of-service ratemaking in 2009". [TEP Application, p. 7] The TCRA would be recovered through a TCRA Charge at an average rate of $0.0126 per kWh. [Id.] TEP explains the TCRA as follows:

> The TCRA represents economic harm that will have been suffered by TEP if the 1999 Settlement Agreement is not honored and generation service rates are based solely on cost-of-service principles. The TCRA will place TEP in the position it would have been but for the 1999 Settlement Agreement. The amount of the TCRA included in the Company's rate request under the Cost-of-Service Methodology is $788 million, which is based on the $111 million revenue deficiency proved in the 2004 Rate Review. Applying this revenue deficiency, the Company has determined that it will have foregone revenues in an amount that will reach $788 million by May 2008. The cumulative balance of the foregone revenues will grow to $921 million by December 2008. However, because TEP believes that the continuation of the collection of CTC revenues beyond May 2008 is a partial mitigation of the losses that TEP has suffered as a result of the 1999 Settlement Agreement not being honored in full, the Company is proposing the lower $788 million balance for the TCRA. [Pignatelli Direct Testimony, p. 20]

**Q. Are there any other aspects of TEP's proposed Cost-of-Service Methodology that you would like to mention?**

A. Yes. Under this methodology TEP is proposing to implement a Purchased Power and Fuel Adjustment Clause (PPFAC). Mr. Pignatelli explains:

> TEP does not currently employ a PPFAC. However, in light of the volatile fuel and purchased power costs experienced in recent years, TEP should have a PPFAC mechanism in place to provide for the timely recovery of fuel and purchased power costs incurred in serving its customers. A PPFAC would serve the best interests of TEP and its customers. [Id.]

Mr. Hutchens further explains:

> TEP relies on significant quantities of natural gas and purchased power to meet its retail load. Although TEP has served the majority of its load with company-owned generating resources, it relies on natural gas and purchased power to meet a growing percentage of its customer demand. This gas and power is

> purchased at market prices, so TEP should be allowed to recover these costs. [Hutchens Direct Testimony, p. 30]

In addition, TEP proposed that its Certificate of Convenience and Necessity ("CC&N") be restored to its former exclusive status.

**Q. What is the rate impact of TEP's proposed Cost-of-Service Methodology?**

A. By the Company's calculations, the Cost-of-Service Methodology would result in a 23.0% increase "based on current expectations for future power supply costs". [TEP Application, p. 3] As I will discuss later in my testimony, a large portion of this proposed increase is directly attributable to the proposed TCRA.

**Q. Can you describe the Company's proposed Hybrid Methodology?**

A. TEP's Hybrid Methodology selectively combines elements of the Cost of Service and Market Methodologies. Under this approach, transmission, distribution and <u>some</u> generation rates would be based on traditional cost of service principles. However, TEP's interest in certain generation assets would be removed from rate base and designated as wholesale assets. [Id.]

> The assets excluded from rate base under the Hybrid Methodology are (i) the Company's interest in Navajo Generating Station Units 1, 2 and 3, and (ii) the Company's interest in Four Corners Generating Station Units 4 and 5 (the "excluded generation assets"). These excluded generation assets will be dedicated to wholesale market transactions, although the power could be used to supply TEP's retail customers at prices reflecting wholesale market conditions. In that circumstance, the cost to supply TEP's retail customers from those excluded generation assets would be recovered through the PPFAC and not base rates. [Id., p. 7]

Notably, TEP is not seeking recovery of any portion of the proposed $788 million TCRA under its proposed Hybrid Methodology, although it does seek recovery of the full $47.5 Million ICRA. The Hybrid Methodology also includes a PPFAC. [Pignatelli Direct Testimony, p. ii] Further, TEP proposes that if its Hybrid Methodology is adopted, TEP's exclusive CC&N would be partially restored. Specifically, TEP proposes that only customers with a demand in excess of 3MW would be permitted to obtain generation service from a competitive provider.

**Q. What is the rate impact of TEP's proposed Hybrid Methodology?**

**A.** By the Company's calculations, the Hybrid method would result in a 14.9% increase "based on current expectations for future power supply costs". [TEP Application, p. 3] This is much less than the impact of the Cost of Service Approach, primarily because the Hybrid Approach doesn't include the TCRA. It is less than the impact of the Market Approach, because fewer generating plants would be moved out of the rate base and thus a larger portion of its generation-related rates would continue to be based on traditional rate setting principles – a much smaller fraction of its generating costs would be tied to the MGC calculations.

**Q. Has TEP provided a comparison of the rate effects of the three different methodologies?**

A. Yes. In response to Staff data request 5.11, TEP provided a forecast of unbundled rates for the three methodologies for the years 2009 through 2015, in comparison to the test year unbundled rates. As shown in the following table, TEP's total test year unbundled rates were 8.42 cents per kWh. Total 2009 rates under the Cost-of-Service, Market and Hybrid Methodologies are forecast to be 23.4%, 21.4% and 15.3% greater than the current unbundled rates, respectively.

| | TEP's | 2009 Forecast Rates | | |
|---|---|---|---|---|
| | Test | Cost of | | |
| **¢ / kWh** | Year | Service | Market | Hybrid |
| Distribution | 1.98 | 1.58 | 1.58 | 1.58 |
| Transmission | 0.78 | 0.70 | 0.70 | 0.70 |
| Must-Run & Ancillary | 0.64 | 0.55 | 0.55 | 0.55 |
| Fixed CTC | 0.97 | NA | NA | NA |
| Floating CTC | (2.67) | NA | NA | NA |
| MGC | 6.66 | NA | 7.39 | NA |
| DSM | 0.06 | NA | NA | NA |
| Generation Non-Fuel | NA | 2.99 | NA | 2.62 |
| PPFAC | NA | 3.31 | NA | 4.25 |
| TCRAC | NA | 1.26 | NA | NA |
| Total | 8.42 | 10.39 | 10.22 | 9.71 |
| | | | | |
| Percent Increase | | 23.4% | 21.4% | 15.3% |

As shown in the following table, total 2015 rates under the Cost-of-Service, Market and Hybrid Methodologies are forecast by TEP to be 34.5%, 16.6% and 25.0% greater than test year rates, respectively.

| | TEP's | 2015 Forecast Rates | | |
|---|---|---|---|---|
| | Test | Cost of | | |
| **¢ / kWh** | Year | Service | Market | Hybrid |
| Distribution | 1.98 | 1.58 | 1.58 | 1.58 |
| Transmission | 0.78 | 0.70 | 0.70 | 0.70 |
| Must-Run & Ancillary | 0.64 | 0.55 | 0.55 | 0.55 |
| Fixed CTC | 0.97 | NA | NA | NA |
| Floating CTC | (2.67) | NA | NA | NA |
| MGC | 6.66 | NA | 6.99 | NA |
| DSM | 0.06 | NA | NA | NA |
| Generation Non-Fuel | NA | 2.99 | NA | 2.62 |
| PPFAC | NA | 4.24 | NA | 5.07 |
| TCRAC | NA | 1.26 | NA | NA |
| Total | 8.42 | 11.33 | 9.82 | 10.53 |
| | | | | |
| Percent Increase | | 34.5% | 16.6% | 25.0% |

This forecast suggests the market approach will be less onerous in future years than it is initially. However, this is tied to the forecast (or assumption) that the MGC will only slightly increase from the test year level of 6.66 cents to 6.99 cents in 2015. Needless to say, there is no assurance that this forecast will come to pass. If natural gas prices continue to escalate, or growth in demand for electricity in California and the Western United States outstrips growth in new supply, spot market prices at Palo Verde could increase dramatically, causing the MGC to escalate far above the level shown in this forecast.

**Critique of TEP's Generation Proposals**

**Q. Let's turn to the next section of your testimony. As you offer your critique of TEP's proposals regarding generation rates, to what degree do you consider the aspects of TEP's proposals relating to the exclusivity of its CC&N?**

A. My comments below are applicable to the aspects of TEP's proposals relating to the pricing of generation regardless of whether the Commission were to decide to restore any exclusivity to TEP's and CC&N. Essentially, I have set aside those aspects of TEP's proposal relating to its CC&N, and I am evaluating only the generation pricing of its proposals. I understand that the issue of whether the Commission wants to maintain a competitive retail generation market structure is under consideration in other dockets, and I do not believe that it would be necessary for the Commission to resolve that issue for TEP in this proceeding. The determination of how TEP's Standard Offer Service is priced is not dependent on any particular resolution of the CC&N question, and any of TEP's pricing mechanisms could theoretically exist whether TEP's CC&N was exclusive or not. While I recognize that the issue of whether the Commission will permit retail electric competition is a significant one, the Commission can evaluate TEP's proposed generation pricing alternatives without having decided whether retail competition will be permitted or not. I recommend that the Commission not make a decision on the future status of TEP's CC&N in this proceeding.

**Q. Can you briefly identify some of your concerns with respect to TEP's proposals relating to market-based generation rates?**

A. Yes. TEP's proposed Market Methodology is based on some incorrect assumptions – that it is entitled to charge market-based generation rates, and that the resulting rates will be just and reasonable. Moreover, TEP's forecast rate comparisons are flawed, and could lead the Commission to incorrect conclusions when evaluating the relative merits of the the proposals.

Finally, TEP's Market Methodology will result in widely fluctuating rates that can easily exceed levels that are just and reasonable. And, even if rates were to average out to a reasonable level over a long period of time (something that has not been demonstrated), the very fact that the rates would fluctuate so widely from month-to-month and year-to-year is a reason for concluding that the proposed Market-based rates would not be just and reasonable.

**Q. Can you briefly explain your first concern, TEP's assumption that it is entitled to charge market-based generation rates?**

A. TEP contends that it has the right to charge customers for electrical generation on the basis of the MGC formula set forth in the 1999 Settlement Agreement. Since it assumes it already has the right to do this, TEP makes little or no effort to argue that this is would be fair, or that the resulting rates would be just and reasonable. As the Commission knows, RUCO strongly disagrees with this assumption. As explained in various pleadings submitted to the Commission, RUCO has a fundamentally different interpretation of the 1999 Settlement Agreement; and, even if TEP's interpretation had some validity, it would not negate the need to demonstrate that the resulting rates will be just and reasonable – something TEP has not even attempted.

**Q. Doesn't the MGC portion of the 1999 Settlement Agreement expire on December 31, 2008?**

A. Yes, it certainly appears that way to me in my reading of the Agreement as a non-lawyer. The purpose of the MGC was to develop the floating CTC, and under the terms of the Settlement Agreement, the floating CTC will expire on December 31, 2008. Logically, after the CTC expires, the MGC will become unnecessary, and thus the provisions relating to the MGC would become moot. I don't see any provisions in the Settlement Agreement that specifically contemplate using the MGC for any purpose other than developing the floating CTC.

**Q. Does TEP agree that the Settlement Agreement calls for the expiration of the MGC at the end of 2008?**

A. No. TEP contends that the Settlement Agreement is silent as to the expiration of the MGC. "While the Floating CTC terminates on December 31, 2008, the agreement set no expiration date for the MGC rate". [Pignatelli Direct Testimony, p. 14] Perhaps more importantly, TEP claims that the MGC is of general applicability – it isn't simply a component used in computing the floating CTC, and that the Settlement Agreement "requires TEP to charge the MGC rate for generation service". [Id.]

In searching the text of the Settlement Agreement, I did not find any references to the MGC except in the section 2, "Stranded Cost Recovery" (pages 4-7 of Attachment No. 1 to Decision 62103). For instance, it says: "The Floating CTC shall be calculated using a Market Generation Credit CMGC") methodology ... and will terminate on December 31, 2008." Similarly, I did not find any statement in the Settlement Agreement concerning how standard offer generation service would be priced, or that prices would be based on spot market prices. In fact, at page 8, under Section 4 Unbundled Rates, there is a provision that states

> TEP's rates shall be fully unbundled into separate charges for: (a) distribution; (b) transmission; (c) metering: (d) billing; (e) ancillary services; (f) fixed must-run generation; (g) system benefits; and (h) standard offer generation, the sum of TEP's standard offer which shall not exceed a customer's current bundled rates.

This language certainly doesn't provide support for the view that the Settlement Agreement mandates a substantial increase in rates above the then-existing level of bundled rates. To the contrary, my impression of this language as a non-lawyer is that the intent was to ensure that standard offer customers (those who continue to purchase energy from TEP) would not face any increase in their rates as a result of the unbundling process or other provisions of the Agreement.

**Q. Can you explain your concern that TEP is simply assuming that rates under its market approach would be fair and reasonable?**

A. Yes. Even if one interpreted the Settlement Agreement as the Commission's expression of support for Standard Offer rates being based on market-priced generation, this policy does not, and cannot, override the constitutional requirement for fair and reasonable rates. Nor does a policy preference for competition automatically ensure that competition will, in fact, exist. Nor is there anything about this policy that would require the Commission to adopt TEP's proposed "market" approach.

It is clear from the decision of the Court of Appeals in the *Phelps Dodge* case that the Commission is responsible for ensuring that all of the rates charged by TEP are just and reasonable – including generation rates. The Commission has broad discretion in deciding whether to implement competitive retail generation rates, but any such action to move in that direction must be consistent with the requirements of the Arizona constitution – the Commission must ensure that rates remain just and reasonable. Yet there is no assurance that market prices will be just and reasonable. The Commission cannot simply assume that market rates will satisfy the just and reasonable standard, particularly under a proposal that will result in a substantial increase in rates above levels that were previously found to be just and reasonable.

**Q. Can you now explain how TEP's rate forecasts might lead the Commission to the wrong conclusion regarding the relative merits of each approach?**

A. Yes. As I explained earlier, TEP estimates that its proposed Market, Cost-of-Service and Hybrid methods will result in rate increases of 21.9%, 23.0% and 14.9%, respectively. TEP's rate comparisons give the impression that the Hybrid approach is less costly for consumers. The hybrid approach appears to be the most favorable because it doesn't include the $788 million TCRA. The Cost of Service approach would show even lower costs, if the TCRA were excluded from that approach as well. Clearly, these comparisons hinge on the relevance, appropriateness, and magnitude of the TCRA. If the TCRA were rejected the comparison would shift in favor of the cost of service approach; similarly, even if the concept of a TCRA were accepted, but TEP's calculations were rejected, and a much smaller TCRA were approved, the comparison would look strikingly different.

**Q. Are there other flaws in TEP's comparison of forecast rates?**

A. Yes. The rates forecast by TEP under each of its proposed methodologies are based upon a particular view of disputed facts, and they are based on a particular set of market projections, and they do not adequately portray the potential for significantly different outcomes, depending on future market volatility and uncertainties.

**Q. Can you please explain how the forecast rates are based on the Company's particular view of disputed facts?**

A. Yes. Key components of each forecast are dependent on a variety of different revenue requirement and ratemaking calculations that are disputed by other parties. These disputes are particularly significant with regard to the proposed TCRA that TEP proposes to include as part of the Cost-of-Service Methodology. The TCRA is based entirely on calculations that are inherently controversial and speculative. As TEP's witness explains, the $788 million TCRA "is based on the $111 million revenue deficiency *proved* in the 2004 Rate Review". [Pignatelli Direct Testimony, p. 20, emphasis added] However, the $111 million revenue deficiency was merely alleged by TEP, it was never proven, nor did the Commission ever make any findings of fact concerning the existence, or magnitude of a revenue deficiency at that time. In fact, the Staff and RUCO provided evidence which suggested a revenue deficiency of $111 million did *not* exist. To the extent these other parties believed a revenue deficiency existed, they believed it was significantly less than the amount claimed by TEP. The Commission concluded that proceeding without making any determination regarding TEP's revenue requirements.

**Q. What would be the effect of removing the TCRA from TEP's cost of service rate forecast?**

A. As shown in the table below, removing the TCRA would bring rates down to levels that are much closer to the existing rates. Rates would increase by 8.4% in 2009, gradually trending up to a total 19.5% increase by 2015. It should be noted that these calculations assume that TEP prevails on all disputed revenue requirement issues, and that the proposed PPFAC is accepted – contrary to RUCO's recommendations in this proceeding. If RUCO's positions were adopted instead, rates would be substantially lower throughout this time period, and much closer to the existing level of rates.

| | TEP's | Cost of Service Forecast Rates | | |
|---|---|---|---|---|
| **¢ / kWh** | Test Year | 2009 | 2012 | 2015 |
| Distribution | 1.98 | 1.58 | 1.58 | 1.58 |
| Transmission | 0.78 | 0.70 | 0.70 | 0.70 |
| Must-Run & Ancillary | 0.64 | 0.55 | 0.55 | 0.55 |
| Fixed CTC | 0.97 | NA | NA | NA |
| Floating CTC | (2.67) | NA | NA | NA |
| MGC | 6.66 | NA | NA | NA |
| DSM | 0.06 | NA | NA | NA |
| Generation Non-Fuel | NA | 2.99 | 2.99 | 2.99 |
| PPFAC | NA | 3.31 | 3.72 | 4.24 |
| Total | 8.42 | 9.13 | 9.54 | 10.07 |
| | | | | |
| Percent Increase | | 8.4% | 13.3% | 19.5% |

**Q. Can you please comment on TEP's request that it be "compensated" for harm it allegedly suffered as a result of the 1999 Settlement Agreement – the underlying premise of the TCRA proposal?**

A. Yes. TEP's TCRA calculations are based purely on its perspective, without considering the perspective of customers. The Court of Appeals in *Phelps Dodge* has clearly stated that a "just and reasonable" analysis must ensure that rates are fair to both consumers and the regulated

Company.

Even if the Commission were willing to compensate TEP for any impacts of a perceived failure to abide by the 1999 Settlement Agreement, it should not rely on TEP's claims concerning its revenue deficiency during past years. Those calculations are highly speculative and they are inconsistent with the analogous calculations developed during the 2004 rate review by the Staff and other parties. There is simply no way of knowing whether, in the absence of the rate freeze provided by the 1999 Settlement Agreement, the Commission would have approved a rate increase during this time period, and if so what the magnitude of such an increase would have been.

There is no "entitlement" to increase rates in the future merely because TEP believes rates were too low in the past, or that a revenue deficiency existed during portions of the time period when its rates were frozen. Furthermore, it is a matter of pure speculation to conjecture whether the Commission would have computed any specific revenue deficiency, or that it would have approved a rate increase, or what the magnitude of such an increase would have been, if rates had not been frozen during this time period.

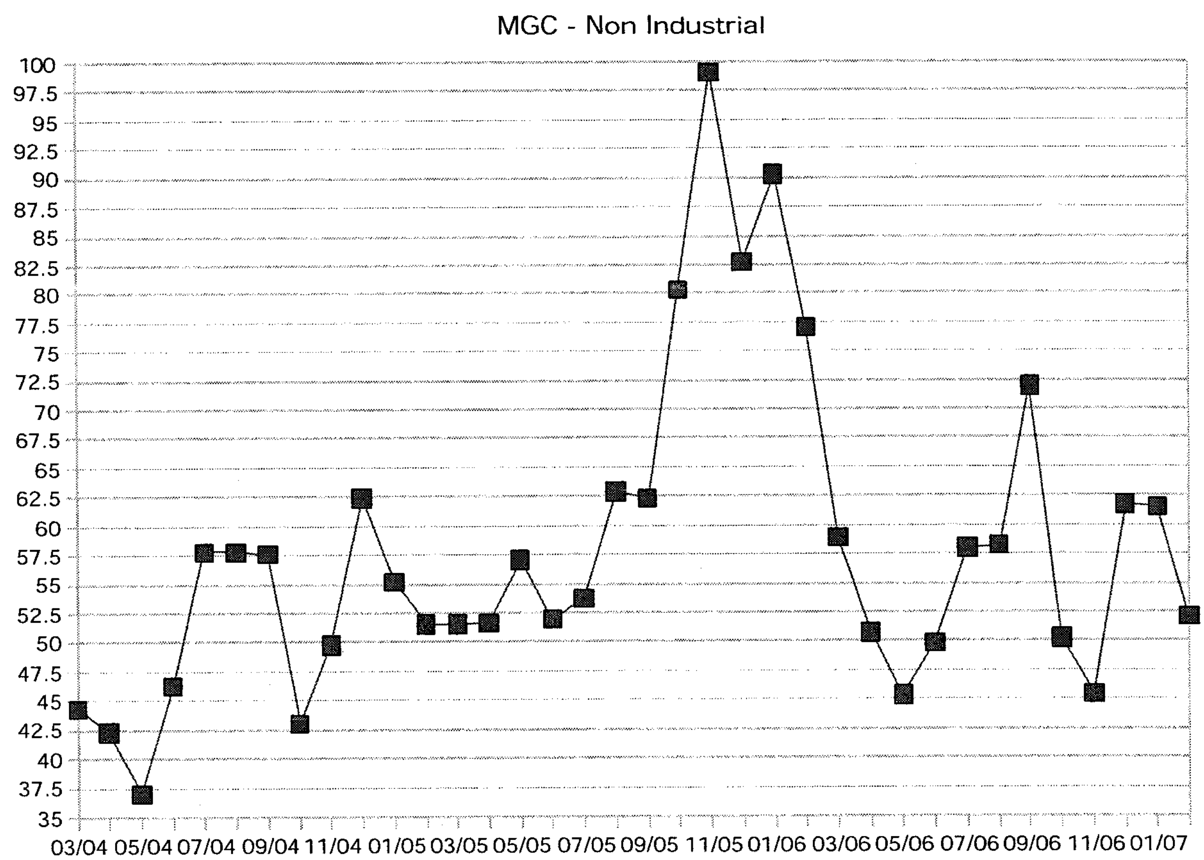
**Q. You mentioned that TEP's rate forecasts don't adequately portray significant differences in volatility and risk. Can you please explain this concern?**

A. Yes. As I explained, under TEP's proposed Market Methodology, generation rates would be based on the MGC, which will fluctuate from month to month. Under the proposed Market Methodology, rates paid by TEP's customers' will depend heavily on a rate component that will fluctuate from month to month; in fact, according to TEP's forecasts, the MGC will represent approximately 70% of the total rate paid by TEP's customers. Yet, the MGC can fluctuate dramatically, in response to fluctuations in natural gas prices, and imbalances in supply and demand conditions. Recent history has shown the magnitude of these fluctuations can be very dramatic, despite the fact that the fact that the actual cost of generating most of the power used by TEP's customers is relatively stable.

Exhibit DGH-12, attached to Mr. Hutchen's direct testimony, shows monthly MGC values from January 2000 through February 2007. For convenience, I've reproduced the data in the table below. As shown, during this time period the MGC for non-industrial customers has been as low as \$18.56 per month in March 2002, and as high as \$315.63 per month in August 2001 – a difference of more than 1,500%.

| Date | MGC Industrial | MGC Other | Date | MGC Industrial | MGC Other |
|---|---|---|---|---|---|
| 01/00 | 24.17 | 25.10 | 08/03 | 51.02 | 52.96 |
| 02/00 | 22.78 | 23.65 | 09/03 | 42.43 | 44.04 |
| 03/00 | 21.37 | 22.17 | 10/03 | 41.23 | 42.81 |
| 04/00 | 29.21 | 30.30 | 11/03 | 38.37 | 39.84 |
| 05/00 | 27.14 | 28.15 | 12/03 | 37.19 | 38.62 |
| 06/00 | 28.57 | 29.62 | 01/04 | 39.90 | 41.43 |
| 07/00 | 54.37 | 56.36 | 02/04 | 45.46 | 47.20 |
| 08/00 | 73.47 | 76.22 | 03/04 | 42.69 | 44.33 |
| 09/00 | 60.99 | 63.27 | 04/04 | 40.71 | 42.26 |
| 10/00 | 75.40 | 78.24 | 05/04 | 35.71 | 37.06 |
| 11/00 | 51.61 | 53.55 | 06/04 | 44.61 | 46.30 |
| 12/00 | 55.63 | 57.71 | 07/04 | 55.68 | 57.79 |
| 01/01 | 60.67 | 62.97 | 08/04 | 55.68 | 57.80 |
| 02/01 | 59.58 | 61.84 | 09/04 | 55.47 | 57.58 |
| 03/01 | 52.51 | 54.50 | 10/04 | 41.46 | 43.05 |
| 04/01 | 201.36 | 209.07 | 11/04 | 47.91 | 49.75 |
| 05/01 | 170.89 | 177.42 | 12/04 | 60.08 | 62.39 |
| 06/01 | 176.53 | 183.25 | 01/05 | 53.17 | 55.20 |
| 07/01 | 272.88 | 283.31 | 02/05 | 49.60 | 51.50 |
| 08/01 | 304.02 | 315.63 | 03/05 | 49.60 | 51.50 |
| 09/01 | 193.18 | 200.57 | 04/05 | 49.74 | 51.64 |
| 10/01 | 33.16 | 34.41 | 05/05 | 54.94 | 57.04 |
| 11/01 | 33.87 | 35.14 | 06/05 | 50.01 | 51.91 |
| 12/01 | 35.87 | 37.23 | 07/05 | 51.76 | 53.73 |
| 01/02 | 25.44 | 26.39 | 08/05 | 60.60 | 62.90 |
| 02/02 | 22.03 | 22.85 | 09/05 | 60.04 | 62.33 |
| 03/02 | 17.90 | 18.56 | 10/05 | 77.38 | 80.34 |
| 04/02 | 20.08 | 20.83 | 11/05 | 95.49 | 99.15 |
| 05/02 | 24.08 | 24.96 | 12/05 | 79.70 | 82.76 |
| 06/02 | 28.56 | 29.60 | 01/06 | 86.97 | 90.31 |
| 07/02 | 31.02 | 32.15 | 02/06 | 74.26 | 77.11 |
| 08/02 | 36.45 | 37.78 | 03/06 | 56.70 | 58.88 |
| 09/02 | 30.16 | 31.27 | 04/06 | 48.86 | 50.74 |
| 10/02 | 28.61 | 29.68 | 05/06 | 43.69 | 45.37 |
| 11/02 | 28.34 | 29.40 | 06/06 | 47.99 | 49.83 |
| 12/02 | 33.11 | 34.35 | 07/06 | 55.86 | 58.01 |
| 01/03 | 32.65 | 33.87 | 08/06 | 56.08 | 58.24 |
| 02/03 | 39.38 | 40.87 | 09/06 | 69.32 | 71.98 |
| 03/03 | 42.12 | 43.71 | 10/06 | 48.37 | 50.23 |
| 04/03 | 56.18 | 58.31 | 11/06 | 43.80 | 45.48 |
| 05/03 | 39.03 | 40.49 | 12/06 | 59.44 | 61.73 |
| 06/03 | 37.34 | 38.75 | 01/07 | 59.25 | 61.51 |
| 07/03 | 50.89 | 52.82 | 02/07 | 50.14 | 52.06 |

Admittedly, these extreme fluctuations occurred during an unusual time period, which everyone hopes will never be repeated. But, there are no guarantees that a milder version of the supply/demand imbalances that occurred during during the 2001 California energy crisis will never occur again. In fact, even during the past few years, when market conditions have been relatively calm, the MGC has demonstrated a tendency to fluctuate rather dramatically. The graph below shows the MGC data for the most recent 3 year period – a period which excludes the 2001 California energy crisis. During this time period, the MGC for non industrial customers fluctuated from a low of $37.06 per month in May of 2004, to a high of $99.15 in October, 2005. This period includes month to month price increases of more than 30%, month to month price decreases of more than 25%, and an overall increase from May 2004 to October 2005 of more than 160%



**Q. Why are you concerned about volatility of the MGC?**

A. Under the Company's market proposal, the majority of consumers' rates would be determined by the MGC, and thus fluctuations in the MGC would translate into widely fluctuating rates to be paid by TEP's customers. Even if the average level of MGC-based generation rates were comparable to those that would be charged under traditional cost of service ratemaking over a ten or twenty year period, the instability and unpredictability of rates on a month-to-month or year-to-year basis would still make the market approach completely unacceptable to the vast majority of customers.

It is important to realize that most people are risk averse most of the time – they prefer stability and predictability, and they particularly dislike unpleasant surprises. While some people enjoy gambling small amounts in the hope of gaining a large amount, this is a limited exception to the more general rule: given a choice, most people prefer stability and certainty when it comes to important financial matters – that's why there is a thriving market for insurance, and that's why investors demand higher returns where risk and uncertainty exists.

Given that electricity is such a vital service – one that customers cannot simply do without if the price is too high, or too volatile, it is not reasonable to force customers to pay rates that fluctuate widely. Fluctuating rates would wreak havoc on the budgets of both residential and business customers – making it difficult to plan ahead, and potentially forcing them into dire straits if prices suddenly escalate above anticipated levels. While some local businesses may be able to recoup higher electric costs by simply raising their prices, others would find this impossible to do. Unlike TEP, many local businesses do not enjoy any substantial degree of monopoly power; firms will experience a sharp drop in sales if they attempt to increase prices, as customers buy less of their products, or purchase from businesses located in Phoenix or elsewhere. Thus, they would not be in a position to simply increase or decrease their prices each month, in response to increases or decreases in TEP's rates.

Similarly, widely fluctuating electric rates would create problems for many residential customers. Volatile electric rates would obviously have an adverse impact on senior citizens who are living on a fixed income, but they would also cause a problem for the vast majority of residential customers, who cannot expect their employer to increase their pay every time electric rates increase. And, even if the highs and lows eventually average out, it simply isn't fair to force customers to deal with this sort of extreme uncertainty with respect to something as important, and unavoidable, as their monthly electric bill. Customers need a reasonable degree of predictability with respect to the cost of electricity; so they can make reasonable plans, know how much of their monthly budget they need to set aside for their electric bill, and how much will be available for food, clothing, and other expenses.

As noted by the Court of Appeals in *Phelps Dodge*, Arizona courts "have consistently held that 'just and reasonable rates' are those that are fair to both consumers and public service corporations". [83 P. 3d 573, ¶ 30] The Arizona Supreme Court has held:

> In determining what is a reasonable price to be charged for services by a public service corporation, an examination must be made not only from the point of view of the corporation, but from that of the one served, also. A reasonable rate is not one ascertained solely from considering the bearing of the facts upon the profits of the corporation. The effect of the rate upon persons to whom services are rendered is as deep a concern in the fixing thereof as is the effect upon the stockholders or bondholders. A reasonable rate is one which is as fair as possible to all whose interests are involved. [Id.]

When considering whether rates are just and reasonable, the Commission should not only be concerned with the overall magnitude or average level of rates. It must take all relevant factors into consideration, including the degree of volatility and predictability of the rates. From the consumers' perspective, rates that can vary 10, 20 or 30 percent from one month to the next cannot be considered just and reasonable. The Commission has recently expressed its concern about volatility in electric rates. In APS's most recent rate case, the Commission retained an annual 4 mil per kWh cap on the amount APS' power supply adjustor could change, and rejected Staff's proposal to allow the adjustor to move an unlimited amount each month. [See, Decision No. 69663 at p. 112]

**Q. What about from TEP's perspective? Is the Company facing severe fluctuations in its generation costs from month-to-month?**

A. No. As explained by RUCO witness Marylee Diaz Cortez, the primary source of TEP's power is from coal plants that it owns, or leases on a long term basis. During the test year, TEP generated 81% of power from coal fired plants. [Diaz Cortez Direct Testimony, f.n. 5, p. 27] Another 6.3% was generated from plants that are fueled with natural gas, and just 12.6% was acquired through open market purchases. [Id.]

Clearly, the vast majority of TEP's generating costs are relatively stable and predictable, compared to the MGC rate. To the extent TEP faces uncertainties with respect to the cost of generating electricity from coal, that uncertainty primarily exists during the years when a plant is being planned and constructed, and a source of coal is being obtained. Once the plant is built and contracts have been signed for a long term coal supply, the cost of generating power is quite stable and predictable.

Admittedly, the costs of generating electricity with natural gas is not as predictable on a long term basis – natural gas cannot generally be purchased on a fixed-price, long term basis, and the cost of fuel is a larger proportion of the total cost of a gas plant (the cost of plant construction is generally lower). But, as I said, only a small minority of TEP's generation is subject to this uncertainty – because the vast majority of its power comes from coal plants, where costs are much more predictable.

In effect, TEP's market proposal would force its customers to suffer from precisely the sort of volatility that TEP itself has prudently avoided. While there have been periods when natural gas may have looked very attractive from a total cost of production perspective, TEP has not bet heavily on this fuel source, and thus it has minimized the risks and uncertainties of natural gas prices, which fluctuate widely from month to month and year to year in response to global energy markets. Gas prices are strongly influenced by crude oil prices, as well as energy supply and demand conditions around the globe, and thus by political developments in Russia, Venezuela and the Middle East – factors that are completely beyond the control of TEP, this Commission, or Arizona rate payers. Yet, TEP is asking its customers to pay electric prices that are tied directly to volatile market indexes that are heavily influenced by those same uncertainties.

**Q. You have been discussing the potential volatility of prices under the Market proposal. Would electric prices also vary under the two alternative approaches proposed by TEP?**

A. Yes. Both the Cost-of-Service and Hybrid Methodologies include a PPFAC, which would vary over time. However, the PPFAC would be updated annually, while the MGC is modified every month. Also, as shown in the table above, the PPFAC under both the Cost-of-Service and Hybrid Methodologies would comprise a significantly smaller percentage of overall rates than the MGC under the Market Methodology, and thus rates would not be nearly as volatile, even if the PPFAC is approved. However, it is worth noting that RUCO does not agree with the PPFAC proposal. As explained by Ms. Diaz Cortez, RUCO believes the proposed PPFAC does not meet the Arizona Court of Appeals' eligibility requirements for an automatic adjustment mechanism. RUCO therefore recommends the Commission reject TEP's request for a PPFAC.

**Q. Can competitive market data be used to determine just and reasonable rates?**

A. I doubt it, at least given the current status of competitive markets. In its FERC Form 1 TEP has admitted that retail electric competition is essentially non-existent in its service area. As explained by TEP:

> As a result of the energy crisis in California in 2000 and 2001 and the volatility of natural gas prices, the competitive retail market in Arizona that was anticipated in 1999 did not materialize. In addition, a 2005 Arizona Court of Appeals ruling held certain portions of the ACC's retail competition rules invalid. Currently, none of TEP or UNS Electric's customers are receiving energy from other providers; however we cannot predict if retail competition

will enter the Arizona market. [TEP FERC Form 1, p. K-18]

TEP paints a more encouraging picture of competition at the wholesale level:

> Competition in wholesale markets has greatly escalated due to increased participation by utilities, non-utility generators, independent power producers and other wholesale power marketers and brokers. [id.]

But, even if competition in wholesale spot markets is escalating, that doesn't mean the wholesale market is fully mature, or that the Commission can rely entirely on market price information to establish retail prices that are fair and reasonable.

Among other problems, there is not sufficient market data available for the price of power generated over long time periods, stretching 10 or more years into the future. For instance, the data included in the MGC calculations is focused on short term, or spot-market, transactions; none of the underlying index data extends even 5 years into the future. Yet, the actual costs incurred by TEP are being incurred on a long term, relatively stable basis extending over multiple decades. For instance, the typical base load generating plant has a useful life of 40 or more years, and it is not unheard of for a generating plant to be still operating 60 or more years after it was constructed.

The Commission must ensure that rates are fair to both producers and consumers, that rates are reasonably adequate to cover the full cost of producing power over a typical plant's entire life cycle, and that rates do not greatly exceed those fully compensatory levels, in order to ensure that customers are also treated fairly. It is hard to see how the Commission can reconcile all of these concerns if it were going to tie rates purely to short term market prices – prices that only extend a few years into the future, leaving great uncertainty about the adequacy or excessiveness of price levels in future years – during the later part of the life cycle of a newly constructed plant.

In any event, regardless of whether or not it is theoretically possible to develop just and reasonable rates by relying in part on wholesale market price data, the specific proposal offered by TEP is clearly not up to the task.

**Q. Should the Commission also consider the actual circumstances facing TEP and its customers – including the specific history and costs associated with its generating plants, in determining whether rates are just and reasonable?**

A. Yes, I believe it should. TEP's existing generating plants were all constructed as part of an integrated Generation, Transmission and Distribution utility. This is particularly significant with respect to its coal plants, which required long construction lead times and involve very long operating lives. While these plants offer cost stability, they require investments that stretch over many decades – risks that have historically been borne in part by TEP's customers under the traditional rate making process.

Under the traditional ratemaking process, TEP's customers have been required to reimburse the reasonable and prudent costs incurred by the utility, including the cost of plants that were constructed by the utility to serve its native load, regardless of whether those plants happened to have higher or lower costs than other plants built by other utilities during the same time period, and regardless of whether the resulting total cost of electricity happened to be higher or lower than the spot market price of electricity available for short term purchase from other utilities. Thus, for example, customers were required to pay the full cost of coal-based power, even if short term blocks of natural gas-based power happened to be available on the open market at a lower cost during at a particular point in time.

The equitable principles behind this long-standing arrangement helps explain why the Commission was concerned about the possibility of "stranded" costs, and why it provided the CTC mechanism, to ensure that customers – not TEP – would be responsible for paying for any costs that otherwise might have been "stranded" during a transition to retail competition. In effect, customers were expected to be "guarantors" to ensure that TEP would have an adequate opportunity to recover the full cost of its existing generating plants, even if the cost of power generated by those plants happened to be higher than the going market price.

Moreover, traditional rate making shifts a disproportionate share of the costs of plants onto customers during the early years of a plant's operating life cycle, through the depreciation and return on rate base procedures. Rather than charging a "levelized" price which remains constant over the plant's entire life cycle, or an escalating price that increases with the general level of prices, under traditional cost-based ratemaking principles, rates are highest in the early years, and lowest in the final year's of the plant's life cycle – when the plant is largely, if not entirely depreciated. In a sense, under standard rate making practices, the cost of newly constructed plants is "front-loaded" onto customers, forcing them to pay a disproportionately high portion of the life cycle cost in years right after a new plant goes into service. This burden was offset by the expectation that customers would get the benefit of lower prices in the final years of the plant's life cycle, when the plant is almost entirely depreciated, and thus a relatively small amount would appear in the rate base.

Given this historical practice, it would clearly be unfair and unreasonable to force customers to pay high spot-market based rates now, despite having helped share the burdens and risks associated with TEP's existing generating plants, and despite having paid higher-than-average rates during the early years immediately after these plants went into operation. Stated another way, just as it would not have been fair to TEP to simply ignore the problem of stranded costs if spot market prices are much lower than TEP's actual costs, it would not be fair to customers to simply ignore the analogous problem in the other direction, if spot market prices are high relative to TEP's actual costs.

**Recommendations**

**Q. Let's turn to the final section of your testimony. What do you recommend the Commission do with regard to TEP's proposed treatment of generating costs?**

A. I recommend that the Commission reject both the Market and Hybrid Methodologies. The linchpin for all of TEP's generation proposals is its claim that it is entitled to charge MGC-based rates for generation starting on January 1, 2009. Yet, the 1999 Settlement Agreement does not say anything about how rates will be computed after 2008 – it only indicates that the rate freeze will end, suggesting an opportunity for TEP to request changes in its rates, and an opportunity for other parties to submit evidence concerning what they believe would be reasonable for the Commission to do in response to such a request.

Significantly, TEP ties its claim to provisions in the 1999 Settlement Agreement concerning the MGC, but the MGC is only used to calculate the floating CTC, which provided a mechanism for recovery of stranded costs from customers who start purchasing from competitive energy providers. Since the MGC is not mentioned elsewhere in the Agreement and is not used for any other purpose, there is no logical basis for assuming that the MGC will live on, after the floating CTC expires. It would be doubly unreasonable for the MGC to live on indefinitely, and to effectively control the level of rates paid by captive customers, considering that TEP never even experienced a rush of customers leaving its system to purchase from competing energy providers, and thus it never actually suffered from the problem of stranded costs which led to creation of both the MGC and the CTC in the first place.

I would also note that, the Commission should keep in mind that its responsibilities go far beyond simply resolving a dispute over language in a legal document. There are overriding public policy considerations which must concern the Commission, and the proper resolution of this issue should take those public policy considerations into account. However the 1999 Settlement Agreement is interpreted, it cannot, and should not, be the only factor considered by the Commission, because that document does not in any way supersede this Commission's obligations to ensure that rates are just and reasonable. That constitutional obligation requires the Commission to take appropriate steps to ensure that customers are treated fairly, regardless of how that document is worded.

**Q. What methodology should the Commission use to set generation rates?**

A. The Market and Hybrid methodologies should not be used, because they will result in excessive, unreasonably volatile rates, which would impose an unnecessary and unreasonable burden on customers.

I recommend the Commission use a traditional cost-of-service methodology in setting all rates, including generation rates. However, RUCO recommend the Commission reject TEP's proposed TCRA Charge, because it is based upon incorrect premises is further explained by RUCO witness Marylee Diaz Cortez. Further, TEP's TCRA calculations are highly speculative, and they are based upon disputed claims regarding an alleged revenue deficiency – claims that were never resolved by the Commission. For all these reasons, the TCRA proposal should be rejected.

**Q. Does this conclude your testimony prefiled on February 29, 2008?**

A. Yes, it does.

Appendix A

## Qualifications

***Present Occupation***

**Q. What is your present occupation?**

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

***Educational Background***

**Q. What is your educational background?**

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

***Clients***

**Q. What types of clients employ your firm?**

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

## Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

## Other Government Agencies

Canada—Department of Communications
Hillsborough County Property Appraiser
Provincial Governments of Canada
Sarasota County Property Appraiser
State of Florida—Department of General Services
United States Department of Justice—Antitrust Division
Utah State Tax Commission

## Regulated Firms

Alabama Power Company
Americall LDC, Inc.
BC Rail
CommuniGroup
Florida Association of Concerned Telephone Companies, Inc.
LDDS Communications, Inc.
Louisiana/Mississippi Resellers Association
Madison County Telephone Company
Montana Power Company
Mountain View Telephone Company
Nevada Power Company
Network I, Inc.
North Carolina Long Distance Association
Northern Lights Public Utility
Otter Tail Power Company
Pan-Alberta Gas, Ltd.
Resort Village Utility, Inc.
South Carolina Long Distance Association
Stanton Telephone

Teleconnect Company

Tennessee Resellers' Association

Westel Telecommunications

Yelcot Telephone Company, Inc.

Other Private Organizations

Arizona Center for Law in the Public Interest

Black United Fund of New Jersey

Casco Bank and Trust

Coalition of Boise Water Customers

Colorado Energy Advocacy Office

East Maine Medical Center

Georgia Legal Services Program

Harris Corporation

Helca Mining Company

Idaho Small Timber Companies

Independent Energy Producers of Idaho

Interstate Securities Corporation

J.R. Simplot Company

Merrill Trust Company

MICRON Semiconductor, Inc.

Native American Rights Fund

PenBay Memorial Hospital

Rosebud Enterprises, Inc.

Skokomish Indian Tribe

State Farm Insurance Company

Twin Falls Canal Company

World Center for Birds of Prey

***Prior Experience***

**Q. Before becoming a consultant, what was your employment experience?**

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

**Q. In how many formal utility regulatory proceedings have you been involved?**

A. As a result of my experience with the Florida Public Counsel and my work as a consulting economist, I have been actively involved in approximately 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

**Q. Have you done any independent research and analysis in the field of regulatory economics?**

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Many of the resulting reports were prepared for the internal use of the Florida Public Counsel. Others were prepared for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

**Q. Have you testified previously as an expert witness in the area of public utility regulation?**

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

**Q. What types of companies have you analyzed?**

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

***Teaching and Publications***

**Q. Have you ever lectured on the subject of regulatory economics?**

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

**Q. Have you published any articles concerning public utility regulation?**

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

***Professional Memberships***

**Q. Do you belong to any professional societies?**

A. Yes. I am a member of the American Economic Association.

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

# COST OF SERVICE AND RATE DESIGN TESTIMONY
OF
GLEN E. GREGORY

ON BEHALF OF
THE
RESIDENTIAL UTILITY CONSUMER OFFICE

MARCH 14, 2008

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**Schedules**

## WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: **Please state your name and business address.**

A: My name is Glen E. Gregory and my business address is 211 North Robinson Avenue, Suite 340, Oklahoma City, Oklahoma 73102.

Q: **What is your occupation?**

A: I am an independent consultant specializing in public utility issues, such as cost of capital, cost of service, and rate design.

Q: **On whose behalf are you appearing in these proceedings?**

A: I am appearing on behalf of the Residential Utility Consumer Office ("RUCO"). The Residential Utility Consumer Office was established by the Arizona Legislature in 1983 to represent the interests of residential utility ratepayers in rate-related proceedings involving public service corporations before the Arizona Corporation Commission ("ACC" or "Commission").

Q: **Please describe your educational and professional qualifications.**

A: My educational qualifications consist of a Bachelor of Arts degree from the University of Oklahoma and a Masters of Arts in Economics from the University of Oklahoma. I also hold the professional designation Certified Rate of Return Analyst ("CRRA") as conferred by the Society of Utility and Regulatory Financial Analyst of which I have been a member since 1996. This designation is awarded based upon experience and successful completion of a written examination.

As regards to my professional experience, I was employed by the Oklahoma Corporation Commission for over 20 years in a supervisory position. My employment within the Commission's Public Utilities Division involved me in a variety of tasks dealing with economic and financial analysis and related research. My primary responsibilities included preparation of reports or testimony regarding cost allocation, rate design, cost of equity estimates, competitive bidding processes, and a variety of other energy-related and regulatory issues. I was also very active in the supervision and training of others in the abovementioned areas. My principal areas of concentration were with electric utility and gas utility regulation. Since leaving the Commission in July of 2003, I have worked on various rate and regulatory matters on behalf of utility customers, municipals, and the Attorney General of Oklahoma. A partial list of testimony given before the Oklahoma Corporation Commission is contained in my resume, which is attached to the end of my testimony as Appendix A.

**Q: Have you testified previously before the Arizona Corporation Commission in proceedings concerned with cost-of-service and rate design issues?**

A: No. This is my first appearance before the Arizona Corporation Commission.

## PURPOSE OF TESTIMONY

**Q: What is the purpose of your testimony in this proceeding?**

A: The purpose of this testimony is to address class cost of service ("CCOS") revenue allocation and rate design issues on behalf of the Residential Utility Consumer Office. In this testimony, I will discuss Tucson Electric Power Company's ("TEP") class cost of service and allocations and will make appropriate recommended changes to cost allocation methods. I will review TEP's proposals related to the allocation of TEP's requested increases to various customer classes and make appropriate recommendations. I will review TEP's proposed rate design and recommend appropriate changes.

**Q: Why are rate design and cost of service issues important to the Residential Utility Consumer Office?**

A: The rate design issues are especially important to RUCO in this case given the magnitude of TEP's requested revenue increase along with TEP's proposed residential rate design changes. TEP's proposed residential rate design changes, even without a revenue increase, would result in significant changes in cost recovery from the various residential customers. The TEP cost of service study is of interest to RUCO in that its conclusions will be considered by the ACC in the determination of rates to the various classes and rate structures within the classes.

## CLASS COST OF SERVICE STUDY

**PRODUCTION COST**

**Q: What allocation method did TEP use to allocate production costs?**

A: TEP advocates the use of the Average and Peaks demand method for the allocation of production capacity cost. The version of the Average and Peaks method used by TEP is the "4CP & Average" method which incorporates class summer months' ("June to September") coincidental peaks ("CP") to calculate the demand component.

**Q: Briefly describe the average and peaks method.**

A: The Average and Peaks method is just one of many methods that can used to allocate production capacity cost. This method was accepted by the ACC in the recent Arizona Public Service Company rate case decision. This 4CP & Average method appropriately considers production plant planning decisions in that it takes into account both system peaks and energy use in the classification and allocation productions costs. The 4CP component recognizes that the utility must build or have access to capacity to meet peak demand on the system, while the energy (average) component recognizes that utilities also build more expensive intermediate and baseload generation plants that run through a greater portion of the year to save on fuel costs. The average component can be thought of as the intermediate and baseload capacity allocator, while the peak component can be thought of as the peaking capacity allocator.

**Q: What is the difference between TEP's Average and Peaks allocator and the calculation of the average and peaks as presented in the NARUC Cost of Service Manual?[1]**

A: The Average and Peaks calculation in the NARUC Manual considers average demand in its derivation of the average demand component of the average and peaks method. The Average and Peaks method supported by TEP refines the average demand component by recognizing the system load factor in the calculation of average demand. The method used by TEP also considers 4 summer peaks instead of the single highest coincident peak.

**Q: Do you believe that the use of the Average and Peaks method to allocate production capacity on the TEP system is appropriate?**

A: Yes. The TEP Average and Peaks method is a very acceptable method for allocating production capacity costs. It becomes even more appropriate if

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[1] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners,(Washington D.C). January, 1992.

the energy allocation is based on energy use by class by time of day and by season, adjusted for the average variable cost during the respective periods as was done by TEP. Their energy factor reflects that consumption during the peak periods of the summer is more costly than an equal amount of consumption during the off-peak winter periods. While no production capacity allocation method balances all cost considerations and issues, the TEP supported Average and Peaks method in conjunction with the TEP supported cost weighted energy allocation factor does consider the differences between base load and peaking load costs for utilities with a seasonal system load.

## TRANSMISSION COST

**Q: How has TEP allocated transmission plant and cost?**

A: TEP advocates the use of the 4CP summer peak demand and average method for the allocation of transmission plant and costs.

**Q: What are your comments regarding the use of the 4CP and Average method to allocate transmission plant and costs to the various customer classes?**

A: The 4CP and Average method recognizes that a utility installs sufficient transmission facilities to maintain stable levels of reliability throughout the year. The 4CP component gives consideration to the fact that TEP is a summer peaking utility. Use of only the 4CP component would suggest that transmission plant is only built and managed to meet the peak load of the system. The decision to build transmission plant should be focused on the ability to deliver energy at the maximum peak without regard to the source of generation or supply. However, transmission plant is related to the size, type of and location of generation units and of course large baseload plants require greater transmission capacity than smaller peaking plants. The 4CP component or other purely peak methods are limited in that they do not consider the fact that a utility installs transmission facilities to maintain stable levels of reliability throughout the year. The Average component recognizes that the transmission plant is built to be used all year around. I recommend that the ACC approve the use of the 4CP and Average method as filed by TEP to allocate transmission plant and related transmission costs to the various classes and customer groups.

Q: **What other methods could be used to allocate transmission plant and costs?**

A: Another method that uses all 12 months of the year that could be used is the 12CP allocation method. The 12CP method has been used extensively by the FERC and also recognizes that a utility installs transmission facilities to maintain stable levels of reliability throughout the year. Both the 12CP method and the 4CP and Average method recognize that transmission plant is used throughout the year. However, I believe the 4CP and Average method may be preferable to the 12CP method in a state like Arizona that has summer peak demand as this summer peak is recognized by the use of the summer's 4CPs. The Average of course recognizes that the transmission plant is built to be used all year around.

**Q: Did you find it necessary to change any of the allocators in the TEP CCOS?**

A: Yes. TEP's CCOS allocated the following other revenue accounts by Sales Revenue from the various classes;

a. Account 450 Forfeited discounts,
b. Account 451 miscellaneous service revenue,
c. Account 454 Rent from electric property,
d. Account 456 Other electric revenues.

The first of these two accounts are more customer specific related. In my experience forfeited discounts (450) for the most part come from residential and small commercial customers; the same holds even more factual for miscellaneous service revenue (451). Therefore I have allocated the current revenue and new proposed revenue from these accounts by the customer count allocator.

Rent from electric property (454) is mostly pole rental and is more properly allocated by the allocator used to distribute the cost of distribution poles. That is what I used to allocate these rents. The other electric revenues (456) are more energy related. Therefore, I used the energy production allocator.

**Q: Have you prepared a class cost of service study?**

A: Yes. I have prepared a class cost of service study which reflects the results of the RUCO Accounting Exhibits. This class cost of service study was prepared using the TEP class cost of service software program. In addition to matching the RUCO Accounting Exhibits, I also made the adjustments to the cost allocations that I previously discussed in this testimony.

**Q: What are the current returns for the different major rate classes as shown by your class cost of service study?**

A: The current returns are summarized in Table 1. The detail of the derivation of the current customer class returns are shown on Schedule GEG-01 attached to this testimony.

**Table 1**

**Rates of Return by Major Class Categories**

| Customer Class | Rate of Return |
|---|---|
| Residential | 2.70% |
| Commercial | 15.08% |
| Industrial | -3.59% |
| Mines | -29.76% |
| Lighting | 2.59% |
| Public Authority | -3.99% |
| Total TEP | 5.43% |

**Q: Have you attached a summary of your proposed class cost of service study?**

A: Yes. The rate base, operating income, rate of return and relative rate of return and other information regarding the six major classes are summarized on my Schedule GEG-01.

## REVENUE ALLOCATION TO THE CLASSES

**Q: Please discuss your recommendation for allocation of the base revenue increase supported by RUCO witness Rodney Moore.**

A: The RUCO proposal is to accept the proposed allocation percentage of any increase to base rates of the various classes as proposed by TEP witness Bentley Erdwurm adjusted of course to the ACC approved revenue requirement. Using the RUCO recommended revenue requirement, this would result in the class revenue increases as shown in Table 2.

# Table 2

## (Allocation of Base Revenue Increase)

| Base Rates | Residential | Commercial | Industrial | Mines | Lighting | Public Authority | TOTAL |
|---|---|---|---|---|---|---|---|
| Allocation % | 45.55% | 37.90% | 8.57% | 5.15% | 0.67% | 2.17% | 100.00% |
| Present | $307,535,130 | $274,527,876 | $53,836,878 | $37,790,355 | $4,077,303 | $13,683,888 | $691,451,429 |
| Proposed | $322,924,533 | $287,331,111 | $56,732,432 | $39,528,967 | $4,302,332 | $14,416,710 | $725,236,086 |
| $ Difference | $15,389,403 | $12,803,236 | $2,895,555 | $1,738,613 | $225,029 | $732,822 | $33,784,657 |
| % Difference | 5.00% | 4.66% | 5.38% | 4.60% | 5.52% | 5.36% | 4.89% |

| | | |
|---|---|---|
| Total Increase | | $36,254,000 |
| Less | Late Payment Revenue and Other Revenue Increases | $2,469,343 |
| Net Base Rate Increase | | $33,784,657 |

This rate spread does provide some limited movement toward strict cost-of-service. It is also important to note that the residential rate restructure as proposed by RUCO will significantly modify the current rate structure. RUCO's proposed rate structure will result in proportionately larger bill increases for higher users of electricity and on-peak users than for the average user and low users of electricity. This proposed restructure of the residential class tariffs will place more responsibility for summer peak usage on the residential customers. This restructure of the residential class tariffs will mean that many residential customers will experience base rate increases greater than the residential class average increase as proposed above. Also the ACC should consider that the restructure of the residential class tariffs if successful in its concept should lead to a lessening of the relative percentage of summer peaks assigned to the residential class in future periods.

## RESIDENTIAL RATE DESIGN

**Q: What are the primary changes in the residential rates proposed by TEP?**

A: The most significant change (other than a substantial overall revenue increase) proposed by TEP is to place more of the residential portion of the Company's proposed rate increase on the larger usage residential customers for both summer rates and to a lesser degree winter rates. TEP has proposed two major changes (1) the standard residential rates proposed by TEP will include the introduction of an inverted block structure (summer and winter) and (2) new customers to the system will be placed on mandatory time-of-use rates.

**Q: Is it appropriate to allocate energy cost in rate pricing to reflect how the use of energy affects the cost incurred by TEP?**

A: Yes. Cost allocations and corresponding rates that reflect time-of-day and seasonal cost patterns can improve the efficiency of use of TEP's power supplies, thereby lowering the cost of energy for all customers. Carefully designed time-of-use rates (and, to a lesser extent, inverted block rates) should result in lower overall system energy costs if consumption of energy is increased during the lower usage (off-peak) periods and consumption is reduced during the higher usage (peak) periods. The optimal result would be a more constant demand for energy across seasons and times of the day. This outcome should not force customers to substantially reduce the amount of energy needed to perform the desired work such as clothes drying, cooking, air conditioning etc.

**Q: Do you believe the residential time-of-use rate designs proposed by TEP can achieve this result?**

A: Most of TEP's residential customers currently are billed on electricity rates that have minimal relation to the true production cost of electricity as it varies over time. The residential time-of-use rates proposed by TEP can give the customers the opportunity to benefit if they can shift usage from higher cost "on-peak" periods to "off-peak" periods. I believe the Company's efforts to design residential time-of-use rates and assign costs over multiple windows of usage is an important step. A significant financial incentive is needed if customers are expected to adjust their electricity usage patterns. The residential time-of-use rates should contain a pricing differential sufficient to motivate customers to adjust their electricity usage patterns.

**Q: Do you have any comments on the TEP recommended time-of-use periods?**

A: TEP has proposed for Pricing Plan R-70N the Summer period (May-October) peak be from 2 p.m. to 6 p.m. with a shoulder-peak period on either side of the peak period of 12 noon to 2 p.m. and 6 p.m. to 8 p.m., resulting in a total of eight hours in the shoulder and peak periods. Sixteen hours of each summer day are considered off-peak. This structure is quite complicated but it does have merit. The limited four hour peak periods should give customers greater ability to shift loads that they might use during peak periods to the shoulder-peak period. As examples, customers could delay the use of dishwashers and clothes washers or dryers until after 6 p.m. or even to the off-peak hour of 8 p.m. Therefore I can support the use of the Summer time periods proposed by TEP.

TEP has proposed that the Winter period (November-April) consist of a morning peak of 6 a.m. to 10 a.m. and an evening peak 5 p.m. to 9 p.m. resulting in a total of eight hours per day of Winter on-peak. Sixteen hours of each winter day are considered off-peak. The winter time periods, while not as important as the summer months' time periods can, also be supported for similar reasons.

**Q: Do you believe that residential time-of-use rates alone will lead to substantial changes in residential usage patterns?**

A: No. Residential customers represent a special challenge for time-of-use based rates. Residential customers will need assistance to become familiar with technologies that can facilitate effective energy management, such as programmable thermostats and direct load controllers. In addition, TEP will need to vigorously pursue education and outreach programs on behalf of the residential customers if increased efficiency on the system is to be obtained.

**Q: What are your recommended modifications to the residential time-of-use rates as proposed by TEP?**

A. My primary modification involves reducing the charges to match the substantially reduced revenue requirement as recommended by RUCO. I have attempted to make these lesser charges still provide sufficient financial incentives for customers to change usage patterns and benefit from the time-based rates.

Another modification that is important was to reduce the total increase to R-70N time-of-use customers to a little less than the system average for the residential class. The reason this is important is that if new residential customers are placed on time-of-use rates it is unlikely that their usage patterns will be the same as the existing time-of-use customers. This is because participation in the current time-of-use program is entirely voluntary, so it would be expected that the current customers have adjusted their usage patterns and installed equipment that allow them to benefit from time-of-use rates. The rates for the new customers should be kept as low as possible in the beginning to facilitate customer acceptance. I have also recommended a lower overall average kWh charge for the new time-of-use rate customer as compared to the standard residential rate customer. However, I would point out that the summer on-peak period hourly charge per kWh will be about 50% more than the charge for the same period for standard residential rate.

**Q: Would the TEP proposed residential time-of-use tariffs with the reduced prices that you have recommended provide residential customers the incentive to respond to the increasing peak energy cost?**

A: Yes. The rates will be much less than TEP has proposed but the incentive between charges will be approximately the same. This differential will provide customers with significant financial incentives to shift load to the off-peak and shoulder-peak hours.

**Q: Do you agree with TEP's proposal to make the residential time-of-use rates mandatory for all new customers?**

A: Yes. TEP currently has few residential time-of-use customers. Carefully developed residential time-of-use rates have the potential to reduce summer peak costs to the utility which in turn will benefit all customers. Arizona Public Service Company has a majority of their residential customers on time-of-use rates and I understand that time-of-use rates have significantly reduced the utility peak load requirements. The mandatory new account aspect of the TEP proposal is crucial if the residential time-of-use rates are expected to result in significant load shifting which should in turn lead to more efficient capital investment and power purchases, and lower electric bills for all customers.

**Q: Does RUCO recommend any exceptions to placement of all new customers on the mandatory residential time-of-use rates?**

A: Yes, but only in limited circumstances. At the time a new customer requests service, TEP's customer service representatives should be required to pose a series of questions to the customer to determine if the customer had special circumstances that would result in time-of-use rates creating a severe hardship. The most obvious example would be persons dependent on life support equipment, or other medical conditions that would prevent the customer from shifting their usage. Certainly any customer that meets part (b) of Pricing Plan R-08 (Residential Lifeline/Medical Life-Support Discount) should be given the option of service under the standard rate plan R-01. Also as a standard practice the customer service representatives should ascertain if the new customer is eligible for TEP's Pricing Plan R-06 (residential Lifeline Discount) which allows qualified customers to receive a discount of $8.00 per month off of their bill. And of course it should be expected that TEP customer representatives will be able to explain to customers the reasons for the time-of-use rates and explain to customers the financial incentives and potential cost savings available from changing usage patterns.

**Q: TEP has also proposed changes to their other residential time-of-use pricing plans. Do you have any comments regarding these pricing plans?**

A: These plans are part of existing pricing plan R-201. This tariff consists of three difference plans called option A, B, and C. Option B and C are currently time-of-use rates. Option A is not.

Option A will become a time-of-use plan similar to the proposed R-70N. The primary difference is that the rate blocks will be divided into three seasons rather than the two seasons for R-70N. The seasons will be Mid-Summer (June-August), Winter (November-April) and Remaining Summer (May, September and October). These seasons correspond with the existing seasons for Option A.

Options B & C currently have the same three seasons as Option A. Option B & C currently have time-of-use blocking structures across the hours of the day very similar to what has been proposed by TEP for pricing plan R-70N. The major difference proposed by TEP is the continuation of the three seasons and some differences in the energy charges. I have made the same changes for these rates as the other residential rates, that is a lower customer charge and lower energy charges to meet the RUCO recommended reduced revenue requirement for the residential classes.

Q: **Do you believe the summer inverted block rate proposed by TEP will lead customers on the standard residential rates (R-01) to reduce air conditioning and other peak time demands?**

A: The inverted block will send customers a more realistic price signal that air conditioning and other types of loads that contribute to the system peak load are expensive to serve. However, since it remains a non-time oriented average cost rate, customers will not have financial incentives to shift load away from peak. Thus, the value of the inverted block structure will be somewhat limited. The inverted rate will, however, more fairly charge customers who desire greater amounts of air conditioning. Likewise, customers using less air conditioning will not be required pay so much of the cost increases as compared to customers using greater than average amounts of air conditioning.

Q: **Please discuss your recommendation regarding the TEP proposed residential customer charge.**

A: TEP has proposed increasing the basic residential customer charge from the current \$4.90 per month to \$9.00. RUCO recommends increasing the customer charge from \$4.90 per month to \$6.50 per month, an increase of \$1.60 per month. This \$6.50 per month charge should recover those "minimum fixed expenses" associated with a customer even if the customer does not use energy for a given month. Generally, the customer charge should recover the Company's investment cost for meters and the service lines as well as their related operations and maintenance expenses. Customer accounting expenses such as meter reading, billing and accounting should be included. I believe the $6.50 charge is sufficient to recover these costs from the average residential customer.

**Q: Are there other reasons to keep the customer charge to a minimum?**

A: Yes. Given the summer peaking nature of the TEP system, RUCO accepts the concept that air conditioning loads are more expensive to serve during peak periods and therefore should be priced accordingly. Customers who choose to use less energy for air conditioning should not be required to pay for the costs created by those who use substantially greater amounts of energy related to air conditioning. A larger-than-needed customer charge reduces the energy charge needed to meet the Company's revenue requirement. If the customer charge covers a substantial portion of the revenue increase, low usage customers such as described above may see a percentage increase in their bills substantially greater than the higher usage customers.

**Q: Will your proposed $6.50 residential customer charge achieve the purpose of preventing undesired greater-than-average increases to low usage customers?**

A: Yes, in conjunction with the lower priced 1st 500 kWh usage block as proposed by TEP and the lower overall revenue requirement supported by RUCO, customers who use lower levels of energy will see a reduction in their monthly bills. This is illustrated in my Schedule GEG-02, which is a typical bill analysis for Residential Rate R-01 customers.

**Q: Please discuss your recommendation regarding the bundled (kWh) charges as proposed by TEP.**

A: As I have discussed elsewhere in this testimony, I have accepted the basic residential rate structure as proposed by TEP. However, the RUCO recommended revenue requirement is substantially less than that proposed by TEP. This will require an adjustment to the bundled energy charges as filed by TEP. I recommend that each of the residential energy charges as proposed by TEP be adjusted downward (after taking into account the customer charge reduction of $2.50 from that proposed by TEP) to meet the residential share (45.5%) of the ACC allowed base revenue increase.

**Q: Have you prepared a schedule presenting proof of your recommended revenue for the residential class?**

A: I have developed a proof of revenue that will produce RUCO's recommended revenue for the residential classes. This proof of revenue with the recommended residential rate design can be found on Schedule GEG-03. I addressed the allocation of revenue increases to the other classes previously; however, I have left it to the representatives of the commercial, industrial and public authority representatives, and the Utility Division Staff to address and make more specific rate design recommendations for the classes other than residential.

**Q: Have you prepared any analysis representing the financial impact of RUCO's residential revenue allocation?**

A: Yes Table 3 below shows the total revenue change to the various TEP residential rate codes.

**Table 3**

**Comparisons of Residential Revenues by Rate Schedules Present and Proposed Rates**

| Class | Current Rate Code | Current Base Revenue | Proposed Base Revenue | Proposed Increase | Increase % |
|---|---|---|---|---|---|
| Residential Service | R-01 Frozen | $292,343,756 | $307,683,024 | $15,339,268 | 5.25% |
| Residential Water Heating - Frozen | R-02 | 312,336 | $319,066 | 6,730 | 2.15% |
| Residential Time of Use | R-21 transferred To R-70N | 3,452,108 | $3,531,561 | 79,453 | 2.30% |
| Residential Time of Use | R70 becomes R-70N | 4,493,407 | $4,449,655 | -43,752 | -0.97% |
| Special Residential Electric Service | R-201AF,R-201BN,R-201CN | 6,933,524 | $6,942,585 | 9,061 | 0.13% |
| Total Residential Revenues | | $307,535,131 | $322,925,890 | $15,390,760 | 5.00% |

## MISCELLANEOUS SERVICE CHARGES

**Q: Have you reviewed TEP's proposed changes and additions to miscellaneous service charges?**

A: Yes I have. Mr. Erdwurm, in his testimony, recommends many increases to current charges and implementation of a late payment fee. The list of the TEP requested changes to miscellaneous service charges are shown in the table on the following page. While RUCO can support the concept that customers rendered specific services contribute to the cost, customer acceptance and public policy issues should also be given consideration.

**Q: Please discuss TEP's proposed changes to existing service fees and the proposed late fee.**

A: Table 4 of the following page was provided by TEP in response to RUCO Data Request 3.14. The prices proposed by TEP are supported by the cost data supplied as part of the response to the RUCO data request. Therefore, RUCO can support the increases to existing service fees as proposed by TEP with the condition that (1) the additional revenue of $2,469,342 be taken into consideration when a new revenue requirement and rates are established by the ACC and (2) that customers be advised in advance of the amount of the after normal working hours fees for the connect and reconnect service.

# Table 4

## Comparisons of Service Revenues by Fees Present and Proposed Fees

| Line | SERVICE REVENUES | TY Fees | TY Revenue | Units | Proposed Fees | TY Revenue Impact |
|---|---|---|---|---|---|---|
| 1<br>2 | Establishment/Re-establishment of Service, service read only<br>-Regular Working Hours | $13.50 | $1,278,990 | 94,740 \1 | $13.50 | $0 |
| 3<br>4 | Establishment of Service Connect or Reconnect under usual operating procedures<br>-Regular Working Hours | $13.50 | $906,255 | 67,130 | $22.00 | $570,605 |
| 5<br>6 | Establishment of Service Connect or Reconnect under usual operating procedures<br>-all hours other then Regular Working Hours | $35.00 | $282,590 | 8,074 | $51.00 | $129,184 |
| 7<br>8 | Establishment of Service Connect or Reconnect under usual operating procedures<br>-Regular Working Hours - Three Phase Metering | $13.50 | $53,042 | 3,929 | $71.00 | $225,918 |
| 9<br>10 | Establishment of Service Connect or Reconnect under usual operating procedures<br>-all hours other then Regular Working Hours - Three Phase Metering | $35.00 | $3,605 | 103 | $198.00 | $16,789 |
| 11 | Customer Requested Meter Rereads | $10.00 | $1,000 | 100.00 | $13.00 | $300 |
| 12 | Late Fee | not applied | | 1,524,986 | 1.5% | $1,524,986 |
| 13 | Metering Field Test | $40.00 | $600 | 15 | $144.00 | $1,560 |
| 14 | TOTAL TY ACTIVITY AND ADJUSTMENT TO SERVICE REVENUES | | $2,526,082 | | | **$2,469,342** |

**Q: Does this conclude your direct testimony?**

A: Yes, it does.

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006



## SUMMARY OF CLASS COST OF SERVICE AND PROPOSED REVENUE ALLOCATION TO CLASSES

| | TOTAL | Residential | Commercial | Industrial | Mines | Lighting | Public Authority |
|---|---|---|---|---|---|---|---|
| RATE BASE | $935,976,517 | $480,254,000 | $337,617,525 | $49,296,694 | $35,602,979 | $9,762,941 | $23,442,379 |
| OPERATING INCOME | $50,843,841 | $12,971,419 | $50,923,748 | ($1,772,177) | ($10,596,908) | $252,525 | ($934,766) |
| RATE OF RETURN (PRES RATES) | 5.43% | 2.70% | 15.08% | -3.59% | -29.76% | 2.59% | -3.99% |
| INDEX RATE OF RETURN (PRESENT) | 1.00 | 0.50 | 2.78 | -0.66 | -5.48 | 0.48 | -0.73 |
| CURRENT BASE REVENUES | $691,451,429 | $307,535,130 | $274,527,876 | $53,836,878 | $37,790,355 | $4,077,303 | $13,683,888 |
| OTHER OPERATING REVENUE | $205,760,263 | $94,173,488 | $74,416,418 | $17,877,822 | $14,245,516 | $709,617 | $4,337,401 |
| TOTAL AVAILABLE REVENUE | $897,211,693 | $401,708,618 | $348,944,294 | $71,714,700 | $52,035,871 | $4,786,921 | $18,021,289 |
| PROPOSED BASE REVENUES | $725,236,086 | $322,924,533 | $287,331,111 | $56,732,432 | $39,528,967 | $4,302,332 | $14,416,710 |
| PROPOSED OTHER OPER REVENUE | $208,229,606 | $96,025,495 | $75,033,754 | $17,877,822 | $14,245,516 | $709,617 | $4,337,401 |
| TOTAL PROPOSED ANNUAL REVENUE | $933,465,693 | $417,098,021 | $361,747,530 | $74,610,254 | $53,774,483 | $5,011,950 | $18,754,111 |
| **INCREASE TO BASE RATES** | **$33,784,657** | **$15,389,403** | **$12,803,236** | **$2,895,555** | **$1,738,613** | **$225,029** | **$732,822** |
| BASE RATE PERCENT INCREASE | 4.89% | 5.00% | 4.66% | 5.38% | 4.60% | 5.52% | 5.36% |
| INCREASE OTHER OPER REVENUE | $2,469,343 | $2,209,367 | $213,430 | $86 | $12 | $38,465 | $7,983 |
| TOTAL INCREASE TO RATES | **$36,254,000** | **$17,598,771** | **$13,016,665** | **$2,895,641** | **$1,738,625** | **$263,494** | **$740,805** |
| TOTAL REVENUE PERCENT INCREASE | 4.04% | 4.38% | 3.73% | 4.04% | 3.34% | 5.50% | 4.11% |

TYPICAL RESIDENTIAL BILL ANALYSIS

| RESIDENTIAL RATE R-01 | PRESENT RATES* | TEP PROPOSED | RUCO PROPOSED |
|---|---|---|---|
| All Months: Customer Charge per Month | $4.90 | $9.00 | $6.50 |
| Summer Energy Charge First 500 kWh | 0.090921 | 0.079062 | 0.074144 |
| Summer Energy Charge, Next 3,000 kWh | 0.090921 | 0.107062 | 0.094144 |
| Summer Energy Charge, All Over 3,000 kWh | 0.090921 | 0.117062 | 0.104144 |
| Winter Charge First 500 kWh | 0.078970 | 0.077062 | 0.064144 |
| Winter Energy Charge, Next 3,000 kWh | 0.078970 | 0.097062 | 0.084144 |
| Winter Energy Charge, All Over 3,000 kWh | 0.078970 | 0.107062 | 0.094144 |

| **RESIDENTIAL BILL COMPARISONS** Monthly Electric Bills at Different Usage Levels | KWH USED | PRESENT MONTHLY COST | RUCO PROPOSED MONTHLY COST | RUCO PROPOSED MONTHLY INCREASE | RUCO PROPOSED MONTHLY % INCREASE |
|---|---|---|---|---|---|
| Residential Service - R-01 Summer | 250 | $27.63 | $25.04 | $(2.59) | -9.39% |
| May-October | 500 | $50.36 | $43.57 | $(6.79) | -13.48% |
| | 1,000 | $95.82 | $90.64 | $(5.18) | -5.40% |
| | 2,000 | $186.74 | $184.79 | $(1.95) | -1.05% |
| | 3,500 | $323.12 | $326.00 | $2.88 | 0.89% |
| | 5,000 | $459.51 | $482.22 | $22.72 | 4.94% |
| Residential Service - R-01 Winter | 250 | $24.64 | $22.54 | $(2.11) | -8.55% |
| November-April | 500 | $44.39 | $38.57 | $(5.81) | -13.10% |
| | 1,000 | $83.87 | $80.64 | $(3.23) | -3.85% |
| | 2,000 | $162.84 | $164.79 | $1.95 | 1.20% |
| | 3,500 | $281.30 | $291.00 | $9.71 | 3.45% |
| | 5,000 | $399.75 | $432.22 | $32.47 | 8.12% |

**** Includes CTC Charges. All columns also include DSM Charges***

RESIDENTIAL RATE DESIGN AND RUCO RECOMMENDED REQUIRED REVENUE

| Description | Billing Determinants | | Rates and Charges | Base Revenue Calculated |
|---|---|---|---|---|
| **RESIDENTIAL- R01 - FROZEN** | | | | |
| Customers (Single-Phase) | 4,102,937 | | $6.50 | $26,669,088 |
| Customer (Three-Phase) | 3,804 | | 12.5 | 47,550 |
| Summer | | | | |
| 1st 500 kWhs | 157,191,445 | | 0.062974 | 9,898,976 |
| 3,000 kWhs | 1,944,859,708 | | 0.082974 | 161,372,810 |
| 3,501 kWhs and above | 140,610,250 | | 0.092974 | 13,073,099 |
| Winter | | | | |
| 1st 500 kWhs | 280,753,681 | | 0.052974 | 14,872,648 |
| 3,000 kWhs | 1,095,328,529 | | 0.072974 | 79,930,516 |
| 3,501 kWhs and above | 21,914,549 | | 0.082974 | 1,818,338 |
| Total kwhs | 3,640,658,163 | Average per kWh | 0.084513 | |
| TOTAL BUNDLED REVENUE | | | | $307,683,024 |
| **RESIDENTIAL WATER HEATING - R-02** | | | | |
| Customers | 28,728 | | | |
| 1st 100 kWhs - is a customer charge | 2,472,456 | | 0.0606527 | 149,961 |
| All kWhs | 2,788,089 | | 0.0606527 | 169,105 |
| Total kwhs | 5,260,545 | | | $319,066 |
| TOTAL BUNDLED REVENUE | | | | $319,066 |
| **RESIDENTIAL TIME OF USE - R-21 - ELIMINATED - REPLACED BY NEW TIME OF USE - R-70N** | | | | |
| Customers | 34,512 | | $6.50 | 224,328 |
| Summer On Peak | | | | |
| 1st 500 kWhs | 60,039 | | 0.0985061 | 5,914 |
| 3,000 kWhs | 5,382,124 | | 0.1185061 | 637,815 |
| 3,501 kWhs and above | 906,035 | | 0.1285061 | 116,431 |
| Summer Off Peak | | | | |
| 1st 500 kWhs | 169,990 | | 0.0257561 | 4,378 |
| 3,000 kWhs | 15,238,671 | | 0.0457561 | 697,262 |
| 3,501 kWhs and above | 2,565,301 | | 0.0557561 | 143,031 |
| Summer Shoulder Peak | | | | |
| 1st 500 kWhs | 61,896 | | 0.0561469 | 3,475 |
| 3,000 kWhs | 5,548,583 | | 0.0761469 | 422,508 |
| 3,501 kWhs and above | 934,057 | | 0.0861469 | 80,466 |
| Winter On Peak | | | | |
| 1st 500 kWhs | 251,797 | | 0.0738277 | 18,590 |
| 3,000 kWhs | 8,069,797 | | 0.0938277 | 757,171 |
| 3,501 kWhs and above | 285,025 | | 0.1038277 | 29,594 |
| Winter Off Peak | | | | |
| 1st 500 kWhs | 384,503 | | 0.0148277 | 5,701 |
| 3,000 kWhs | 12,322,860 | | 0.0298277 | 367,563 |
| 3,501 kWhs and above | 435,244 | | 0.0398277 | 17,335 |
| Total kwhs | 52,615,922 | Average per kWh | 0.0671196 | |
| TOTAL BUNDLED REVENUE | | | | 3,531,561 |

## RESIDENTIAL RATE DESIGN AND RUCO RECOMMENDED REQUIRED REVENUE

| Description | Billing Determinants | | Rates and Charges | Base Revenue Calculated |
|---|---|---|---|---|
| **RESIDENTIAL TIME OF USE - R70 - ELIMINATED - REPLACED BY NEW TIME OF USE - R70N** | | | | |
| Customer Charge | 50,748 | | $6.50 | 329,862 |
| Summer On Peak | | | | |
| 1st 500 kWhs | 201,083 | | 0.0985061 | 19,808 |
| 3,000 kWhs | 8,188,982 | | 0.1185061 | 970,444 |
| 3,501 kWhs and above | 922,065 | | 0.1285061 | 118,491 |
| Summer Off Peak | | | | |
| 1st 500 kWhs | 451,493 | | 0.0257561 | 11,629 |
| 3,000 kWhs | 18,386,781 | | 0.0457561 | 841,308 |
| 3,501 kWhs and above | 2,070,319 | | 0.0557561 | 115,433 |
| Summer Shoulder Peak | | | | |
| 1st 500 kWhs | 186,158 | | 0.0561469 | 10,452 |
| 3,000 kWhs | 7,581,163 | | 0.0761469 | 577,282 |
| 3,501 kWhs and above | 853,625 | | 0.0861469 | 73,537 |
| Winter On Peak | | | | |
| 1st 500 kWhs | 857,727 | | 0.0738277 | 63,324 |
| 3,000 kWhs | 9,151,895 | | 0.0938277 | 858,701 |
| 3,501 kWhs and above | 247,258 | | 0.1038277 | 25,672 |
| Winter Off Peak | | | | |
| 1st 500 kWhs | 1,258,707 | | 0.0148277 | 18,664 |
| 3,000 kWhs | 13,430,319 | | 0.0298277 | 400,596 |
| 3,501 kWhs and above | 362,849 | | 0.0398277 | 14,451 |
| Total kwhs | 64,150,421 | Average per kWh | 0.0693628 | |
| TOTAL BUNDLED REVENUE | | | | 4,449,655 |
| **TOTAL BUNDLED REVENUE NEW R70N** | | | | 7,981,216 |
| **SPECIAL RESIDENTIAL ELECTRIC SERVICE - R-201A - FROZEN** | | | | |
| Customers (Single-Phase) | 86,138 | | $6.50 | 559,900 |
| Mid-Summer | | | | |
| 1st 500 kWhs | 777,880 | | 0.0503978 | 39,203 |
| 3,000 kWhs | 27,076,790 | | 0.0703978 | 1,906,147 |
| 3,501 kWhs and above | 2,295,440 | | 0.0803978 | 184,548 |
| Remaining Summer | | | | |
| 1st 500 kWhs | 920,158 | | 0.0403978 | 37,172 |
| 3,000 kWhs | 21,183,679 | | 0.0603978 | 1,279,448 |
| 3,501 kWhs and above | 790,638 | | 0.0703978 | 55,659 |
| Winter | | | | |
| 1st 500 kWhs | 3,035,325 | | 0.0353978 | 107,444 |
| 3,000 kWhs | 34,712,462 | | 0.0553978 | 1,922,995 |
| 3,501 kWhs and above | 802,397 | | 0.0653978 | 52,475 |
| Total kwhs | 91,594,770 | Average per kWh | 0.0670889 | |
| TOTAL BUNDLED REVENUE | | | | 6,144,992 |

RESIDENTIAL RATE DESIGN AND RUCO RECOMMENDED REQUIRED REVENUE

| Description | Billing Determinants | Rates and Charges | Base Revenue Calculated |
|---|---|---|---|
| **TIME OF USE - R-201B - ELIMINATED - REPLACED BY TIME OF USE - R-201BN** | | | |
| Customers | 6,353 | $6.50 | 41,297 |
| Mid-Summer On Peak | | | |
| 1st 500 kWhs | 10,690 | 0.0793978 | 849 |
| 3,000 kWhs | 465,009 | 0.0993978 | 46,221 |
| 3,501 kWhs and above | 65,778 | 0.0893978 | 5,880 |
| Mid-Summer Off Peak | | | |
| 1st 500 kWhs | 27,686 | 0.0493978 | 1,368 |
| 3,000 kWhs | 1,204,357 | 0.0693978 | 83,580 |
| 3,501 kWhs and above | 170,363 | 0.0593978 | 10,119 |
| Mid-Summer Shoulder Peak | | | |
| 1st 500 kWhs | 10,730 | 0.0593978 | 637 |
| 3,000 kWhs | 466,759 | 0.0793978 | 37,060 |
| 3,501 kWhs and above | 66,026 | 0.0693978 | 4,582 |
| Remaining Summer On Peak | | | |
| 1st 500 kWhs | 17,072 | 0.0693978 | 1,185 |
| 3,000 kWhs | 304,717 | 0.0893978 | 27,241 |
| 3,501 kWhs and above | 33,731 | 0.0793978 | 2,678 |
| Remaining Summer Off Peak | | | |
| 1st 500 kWhs | 42,591 | 0.0393978 | 1,678 |
| 3,000 kWhs | 760,187 | 0.0593978 | 45,153 |
| 3,501 kWhs and above | 84,149 | 0.0493978 | 4,157 |
| Remaining Summer Shoulder Peak | | | |
| 1st 500 kWhs | 15,916 | 0.0493978 | 786 |
| 3,000 kWhs | 284,073 | 0.0693978 | 19,714 |
| 3,501 kWhs and above | 31,446 | 0.0593978 | 1,868 |
| Winter On Peak | | | |
| 1st 500 kWhs | 63,699 | 0.0643978 | 4,102 |
| 3,000 kWhs | 1,178,335 | 0.0843978 | 99,449 |
| 3,501 kWhs and above | 199,932 | 0.0743978 | 14,874 |
| Winter Off Peak | | | |
| 1st 500 kWhs | 92,114 | 0.0543978 | 5,011 |
| 3,000 kWhs | 1,703,963 | 0.0743978 | 126,771 |
| 3,501 kWhs and above | 289,116 | 0.0643978 | 18,618 |
| Total kwhs | 7,588,438 Average per kWh | 0.0797106 | |
| TOTAL BUNDLED REVENUE | | | 604,879 |

RESIDENTIAL RATE DESIGN AND RUCO RECOMMENDED REQUIRED REVENUE

| Description | Billing Determinants | Rates and Charges | Base Revenue Calculated |
|---|---|---|---|
| **TIME OF USE - R-201C - ELIMINATED - REPLACED BY TIME OF USE - R-201CN** | | | |
| Customers | 2,560 | $6.50 | 16,641 |
| Mid-Summer On Peak | | | |
| 1st 500 kWhs | 3,123 | 0.077036 | 241 |
| 3,000 kWhs | 148,154 | 0.096636 | 14,317 |
| 3,501 kWhs and above | 10,826 | 0.086836 | 940 |
| Mid-Summer Off Peak | | | |
| 1st 500 kWhs | 8,752 | 0.047636 | 417 |
| 3,000 kWhs | 415,151 | 0.067236 | 27,913 |
| 3,501 kWhs and above | 30,336 | 0.057436 | 1,742 |
| Mid-Summer Shoulder Peak | | | |
| 1st 500 kWhs | 3,343 | 0.057436 | 192 |
| 3,000 kWhs | 158,596 | 0.077036 | 12,218 |
| 3,501 kWhs and above | 11,589 | 0.067236 | 779 |
| Remaining Summer On Peak | | | |
| 1st 500 kWhs | 12,795 | 0.067236 | 860 |
| 3,000 kWhs | 100,676 | 0.086836 | 8,742 |
| 3,501 kWhs and above | 6,384 | 0.077036 | 492 |
| Remaining Summer Off Peak | | | |
| 1st 500 kWhs | 36,182 | 0.037836 | 1,369 |
| 3,000 kWhs | 284,699 | 0.057436 | 16,352 |
| 3,501 kWhs and above | 18,054 | 0.047636 | 860 |
| Remaining Summer Shoulder Peak | | | |
| 1st 500 kWhs | 13,494 | 0.047636 | 643 |
| 3,000 kWhs | 106,176 | 0.067236 | 7,139 |
| 3,501 kWhs and above | 6,733 | 0.057436 | 387 |
| Winter On Peak | | | |
| 1st 500 kWhs | 44,725 | 0.062336 | 2,788 |
| 3,000 kWhs | 332,541 | 0.081936 | 27,247 |
| 3,501 kWhs and above | 77,285 | 0.072136 | 5,575 |
| Winter Off Peak | | | |
| 1st 500 kWhs | 64,398 | 0.052536 | 3,383 |
| 3,000 kWhs | 478,820 | 0.072136 | 34,540 |
| 3,501 kWhs and above | 111,281 | 0.062336 | 6,937 |
| Total kwhs | 2,484,111 Average per kWh | 0.0775785 | |
| TOTAL BUNDLED REVENUE | | | 192,714 |
| **TOTAL 201A,B, and C** | | | **6,942,585** |
| **TOTAL PROPOSED RESIDENTIAL BASE REVENUE** | | | **$322,925,890** |

# APPENDIX A

## RESUME OF GLEN GREGORY

**EDUCATION:**

Masters of Arts, Economics, University, of Oklahoma, 1980
Bachelor of Arts, University of Oklahoma, 1975

**CREDENTIALS:**

Certified Rate of Return Analyst, 1996

**EXPERIENCE**

| | |
|---|---|
| • Independent Utility Regulation Consultant | 5 years |
| • Manager, Senior Analyst (utility regulation), | |
| • Oklahoma Corporation Commission | 21 years |

**Independent Consultant,** July 2003 to the present.

Mr. Gregory specializes in public utility issues, such as cost of capital, cost of service, rate design and other public utility issues.

**Oklahoma Corporation Commission,** November 1982 to July 2003.

**Manager, Senior Analyst - Public Utility Division** - Mr. Gregory specialized in the areas of rate design, cost allocation, and financial analysis for cost of capital and rate of return. Mr. Gregory was also substantially involved in preparation of reports and testimony regarding competitive bidding, utility deregulation, utility merger activities, evaluation of state and Federal restructuring proposals and a variety of other energy-related and regulatory issues. As a Certified Rate of Return Analyst, Mr. Gregory was the primary representative of the Division in the area of cost of capital analysis for both electric and gas utilities. Mr. Gregory was responsible for supervision of all cost of service studies, many rate cases for electric, gas, and water utilities. All positions held at the Commission required that Mr. Gregory provide expert testimony and be able to defend it under cross-examination. Mr. Gregory managed the Division's Economic and Research Unit. Mr. Gregory was also very active in the supervision and training of others in my assigned areas of responsibility. Mr. Gregory worked closely with corporate representatives, exchanged information, methodologies, and negotiated settlements.

## Listing of Experience of Glen Gregory Related to Capital Cost, Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

**Entergy Arkansas, 2007** – Participated as an expert witness on behalf of the commercial customers before the Arkansas Public Service Commission in this general rate case to address capital cost, rate design and jurisdictional issues for the purpose of setting prospective cost-of-service based rates. Project completed in August 2007.

**Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-285)** – Participated as an expert witness on behalf of the industrial consumers before the Oklahoma Corporation Commission in PSO's general rate case application to address rate design and jurisdictional issues for the purpose of setting prospective cost-of-service based rates.

**Southwestern Public Service Company, 2006 (PUCT 32766)** – Performed analysis, research regarding shared services, jurisdictional allocation, and other revenue requirement matters concerning this SPS rate case to be heard before the Public Utility Commission of Texas on behalf of various Texas municipal cities.

**ATMOS Energy - Mid-Tex Gas, 2006 (GUD 9676)** – Performed analysis, research regarding shared services, jurisdictional allocation, and other revenue requirement matters concerning this rate case to be heard before the Railroad Commission of Texas on behalf of various Texas municipal cities.

**Oklahoma Gas & Electric Co., 2005 (PUD 200500151)** – Participated as an expert witness on behalf of the industrial consumers before the Oklahoma Corporation Commission in OG&E's general rate case application to address capital cost, rate design and jurisdictional issues for the purpose of setting prospective cost-of-service based rates. Project completed in December 2005.

**Oklahoma Natural Gas Company ("ONG"), 2005 (PUD 200300610)** - Participated as an expert witness on behalf of the Attorney General of the State of Oklahoma before the Oklahoma Corporation Commission in this general rate case to address capital cost, rate design and jurisdictional issues for the purpose of setting prospective cost-of-service based rates. Project completed in August 2005.

**Public Service Company of Oklahoma ("PSO"), 2004 (PUD 200300076** – Participated as an expert witness on behalf of the Oklahoma Industrial Energy Consumers of the State of Oklahoma before the Oklahoma Corporation Commission in this general rate case to capital cost, rate design and jurisdictional issues for the purpose of setting prospective cost-of-service based rates. Project completed in July 2004.

**CenterPoint Energy Arkla ("Arkla"), 2004 (PUD 200400187** – Participated as an expert witness on behalf of the Attorney General of the State of Oklahoma before the Oklahoma Corporation Commission in this general rate case to address capital cost, rate design and jurisdictional issues for the purpose of setting prospective cost-of-service based rates. Project completed in December 2004.

**Oklahoma Gas & Electric Company ("OG&E"), 2004 (PUD 200300226** – Participated as an expert witness on behalf of the Oklahoma Industrial Energy Consumers before the OCC to address capital cost issues.

**Oklahoma Natural Gas Company ("ONG"), 2003 (PUD 200300617)** - Participated as an expert witness on behalf of the Staff of the State of Oklahoma before the OCC in this application of ONG to recover certain cost related to service lines, uncollectible accounts, etc.. Negotiate tariff and cost-of-service issues in settlement discussion.

**Public Service Company of Oklahoma ("PSO"), 2003 (PUD 200200754)** – Performed analysis, research and writing assistance to prepare written testimony on behalf of the Oklahoma Industrial Energy Consumers (OIEC) regarding a review of PSO's Fuel Adjustment Clause for the year 2001.

**Arkansas Louisiana Gas Company ("Arkla"), 2002 (PUD 200200166)** – Participated as an expert witness on behalf of the PUD before the OCC in this general rate case application to address capital cost. Oversaw the work of outside consultants regarding various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates. Negotiated tariff and cost-of-service issues in settlement discussion.

**The Empire District Electric Company., 2003 (PUD 200300121)** – Supervised the work of OCC staff filing testimony on behalf of the PUD before the OCC in this general rate case application regarding various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates. Negotiated tariff and cost-of-service issues in settlement discussion.

**Lawton Cogeneration L.L.C., 2002 (PUD 200200038)** - Performed analysis, research and writing assistance to prepare written testimony on behalf of the PUD regarding a review of avoided cost as required by Federal law and the Power Sale Agreement submitted by Lawton for OCC approval.

**Arkansas Louisiana Gas Company., 2002 (PUD 200100586)** – Participated as an expert witness on behalf of the PUD before the OCC regarding this application for approval of a transfer of Oklahoma assets as part of a corporate restructuring plan..

**Enogex, Inc.., 2001 (PUD 200000339)** – Participated as an expert witness on behalf of the PUD before the OCC in this cause filed by Enogex seeking a determination from the OCC regarding the evaluation of ONG's competitive bid process.

**Oklahoma Gas & Electric Co., 2000 (PUD 200000022)** – Participated as an expert witness on behalf of the PUD before the OCC concerning OG&E's recovery of natural gas transportation cost from its affiliate Enogex, Inc.

**Oklahoma Gas & Electric Co., 2002 (PUD 2001000455)** – Participated as an expert witness on behalf of the PUD before the OCC in this general rate case application to address capital cost and rate design. Supervised and oversaw the work of PUD staff involved in various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates. Negotiate tariff and cost-of-service issues in settlement discussion.

**Oklahoma Gas and Electric Company, 1996 (PUD 960000116)** – Participated as an expert witness on behalf of the PUD before the OCC regarding capital cost and capital structure. Oversaw and supervised the work of the PUD witness regarding revenue, rate design, cost of service matters and tariffs. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.

**Oklahoma Gas and Electric Company, 1999 (PUD 990000417)** – OG&E request for implementation of a performance based incentive plan. Participated as an expert witness and supervised other OCC staff filing testimony on behalf of the PUD before the OCC. Prepared information to inform the Commissioners in OCC Deliberations of matters regarding the application.

**Oklahoma Natural Gas Company, 1998** – Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of the PUD to address the cost of ONG's unbundled upstream gas services.

**Public Service Company of Oklahoma, 1997 (PUD 960000214** - Sponsored testimony before the OCC on behalf of the PUD regarding cost of capital and capital structure.

**Oklahoma Natural Gas /Western Resources Merger, 1997** - Oversaw and supervised the work of the PUD witness assigned on behalf of the PUD before the OCC regarding the appropriateness of OCC approval of the merger and setting certain parameters to safeguard ratepayers from negative effects of the merger.

**Oklahoma Gas and Electric Co., 1996 (CN PUD 960000116)** - Sponsored testimony on behalf of the PUD for the purpose of determining the Company's cost of capital and capital structure. Oversaw and supervised the work of the PUD witness regarding revenue, rate design, cost of service matters and tariffs.

**Arkansas Oklahoma Gas Company, 1997 (CN PUD 960000408)** - Sponsored testimony before the OCC on behalf of the PUD regarding cost of capital and capital structure. Oversaw and supervised the work of the PUD witness regarding revenue, rate design, cost of service matters and tariffs.

**Empire District Electric Company, 1994 (940000343)** - Sponsored testimony before the OCC on behalf of the PUD regarding cost of capital and capital structure. Sponsored testimony before the OCC on behalf of the PUD regarding revenue, rate design, cost of service matters and tariffs.

**Arkansas Louisiana Gas Company, 1993 (920001217)** - Sponsored testimony before the OCC on behalf of the PUD regarding cost of capital and capital structure. Supervised the preparation of PUD testimony regarding revenue, rate design, cost of service matters and tariffs.

**Oklahoma Natural Gas Company, 1993** - Sponsored and or supervised testimony of PUD staff before the OCC on behalf of the PUD regarding capital cost, revenue, rate design, cost of service matters and tariffs.

**Oklahoma Gas and Electric Company, 1992** - Sponsored and or supervised testimony of PUD staff testimony before the OCC on behalf of the PUD regarding capital cost, revenue, rate design, cost of service matters and tariffs.

EXHIBIT
RUCO
2
admitted

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

# RESPONSIVE DIRECT TESTIMONY IN OPPOSITON TO THE PROPOSED SETTLEMENT AGREEMENT

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 2, 2008

## TABLE OF CONTENTS

## INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any previous testimony in this docket?

A. Yes. On February 29, 2008, I filed direct testimony on the cost of capital issues associated with Tucson Electric Power Company's ("TEP" or "the Company") application for a permanent rate increase ("Rate Application"). The filing of surrebuttal testimony was suspended as a result of settlement discussions which began on April 10, 2008. On May 29, 2008, a proposed settlement agreement ("Settlement Agreement" or "Settlement") was filed with the Commission for the purpose of settling disputed issues related to TEP's Rate Application. Appendix I, which is attached to my February 29, 2008 testimony, describes my experience and qualifications in the field of utility regulation.

Q. Did RUCO play a role in the aforementioned settlement discussions?

A. Yes. Members of RUCO's staff, including myself, attended and monitored the aforementioned settlement discussions.

...

Q. Why didn't RUCO take a more active part in the settlement discussions?

A. RUCO became convinced early on that a satisfactory settlement (i.e. one that would be in the best interests of residential ratepayers) could not be reached. This assessment was based on the discussions that took place during the first settlement meeting and the large disparity between TEP's requested rate increase and the recommended levels of increases being recommended by both RUCO and ACC Staff. As a result, RUCO elected not to actively participate in the discussions but did monitor the meetings and make minor suggestions on clarifying language contained in the Settlement Agreement. RUCO has not entered into the Settlement Agreement because RUCO does not believe the Settlement Agreement results in fair and reasonable rates.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present evidence that supports RUCO's position that the Settlement Agreement does not result in fair and reasonable rates.

**OVERVIEW OF THE SETTLEMENT AGREEMENT**

Q. Please provide an overview of the Settlement Agreement that is currently before the ACC.

A. The Settlement Agreement presently before the Commission was negotiated over the seven-week period between April 10, 2008 and May 29, 2008. During that time, various parties to the case reached a consensus to settle a number of disputed issues associated with TEP's Rate Application, which was originally filed on July 2, 2007. The resulting document addresses each of the issues that were resolved by the various parties to the case. Among the issues addressed in the Settlement Agreement are the method in which TEP's rates would be determined (i.e. the traditional cost-of-service methodology), the Company's cost of capital, depreciation and cost of asset removal, TEP's proposed implementation cost recovery asset and Termination Cost Recovery Asset ("TCRA"), a purchased power and fuel adjustment clause, a renewable energy adjustor, a demand-side management adjustor mechanism, and time-of-use rates. The Settlement Agreement also provides for a rate freeze for low-income users and a rate moratorium that would remain in effect until December 31, 2012. The Settlement Agreement also stipulates that TEP shall forego all claims relating to any alleged breach of contract resulting from or related to an earlier 1999 settlement agreement ("1999 Settlement Agreement"), which established the Company's present rates and/or Decision No. 62103, which approved the 1999 Settlement Agreement.

Q. Which of the parties to the case have entered into the Settlement Agreement?

A. The Settlement Agreement was entered into by the following parties: TEP; ACC Staff; Arizonans for Electric Choice and Competition and Phelps Dodge Mining Company[1] (collectively "AECC"); Arizona Community Action Association ("ACAA"); U.S. Department of Defense and all other Federal Executive Agencies ("DOD"); Arizona Investment Council ("AIC"), International Brotherhood of Electric Workers Local 1116 ("IBEW 1116"), Mesquite Power, LLC, Southwestern Power Group II, LLC, Bowie Power Station, LLC, and Sempra Energy Solutions, LLC ("Power Producers"); and Kroger Company (collectively referred to as "Signatories" or "Settling Parties")

Q. Have the Settling Parties characterized the Settlement Agreement as fair, reasonable, and in the public interest?

A. Yes. The testimonies of all the Settling Parties express this notion in various manners. For example the testimony of Staff witness Ernest G. Johnson states "In Staff's opinion, the Proposed Settlement is fair,

[1] Over the course of the TEP rate case proceeding, Phelps Dodge Mining Company was acquired by Freeport-McMoRan Copper & Gold Inc.

balanced, and in the public interest."[2] The testimony of TEP witness James S. Pignatelli states "Underlying this is the need to balance the interests of customers, employees and shareholders. I believe the settlement agreement strikes an appropriate balance and will provide benefits for each of these important groups."[3] The testimony of AECC witness Kevin C. Higgins states, "In my opinion, the 2008 Settlement Agreement produces just and reasonable rates and is in the public interest."[4]

Q. What are some of the reasons the Settling Parties have reached this fair, reasonable, and in the public interest conclusion regarding the Settlement Agreement?

A. The predominant reasons claimed by the Settling Parties are as follows:

1) Minimal rate increase of 6%, or $47.1 million;
2) Adoption of new depreciation rates and the resolution of the FAS 143 issue;
3) Adoption of adjustor clauses for demand-side management and renewable energy programs;
4) A moratorium on base rate increases through 2012;
5) The implementation of a Purchased Power and Fuel Adjustor Charge ("PPFAC");

[2] Direct testimony of Ernest G. Johnson at page 6, lines 25 – 26.
[3] Direct Testimony of James S. Pignatelli at page 9, lines 1 – 3.
[4] Direct Testimony of Kevin C. Higgins at page 2, lines 4 – 5.

6) Adoption of a cost of equity of 10.25% and an overall weighted cost of capital of 8.03%;

7) Waiver of any claims under the 1999 Settlement Agreement; and

8) Availability of Retail Competitive opportunities.

Q. Have the Settling Parties presented any Exhibits that portray the various parties' original positions as compared to the Settlement Agreement?

A. Yes. TEP witness James S. Pignatelli presents such an Exhibit on page 10 of his direct testimony and the Settlement Agreement itself presents Exhibit 2 demonstrating the differences between TEP's original position, Staff's original position, and the Settlement Agreement. There is also an Exhibit RCS-7, attached to Staff witness Ralph C. Smith's direct testimony which shows the differences between the Staff's original position and the Settlement position.

Q. Do the numbers in these exhibits appear to be accurate?

A. Yes, however the manner in which the Settling Parties have portrayed the overall result of the Settlement Agreement presents a false impression of the reasonableness of the Agreement.

...

## THE FALSE IMPRESSION CREATED BY THE SETTLEMENT AGREEMENT

Q. Please explain this false impression.

A. The $47.1 million purported increase of 6% presents a false impression because it is based on the false premise that the fixed CTC is a permanent part of rates rather than a temporary surcharge that was fully recovered earlier this year. The true increase, based on TEP's adjusted current base rates without the fixed CTC equals 19.8%.[5] The Settlement Agreement revenue requirement comparison charts in Mr. Pignatelli's testimony are misleading because they do not represent apples-to-apples comparisons between the terms of the Settlement and the real increases the customers will bear under the Settlement.

Q. Why are they not apples-to-apples comparisons?

A. The Company and RUCO's original revenue requirement positions were based on a base cost of fuel and purchased power of $.033 per kWh. The Staff's original position and the Settlement Agreement include a base cost of gas of only $.028896 per kWh. The delta between the two amounts is approximately $.0041 per kWh, which when multiplied by test year adjusted kWh sales renders a difference of over $38 million. Since the Settlement Agreement contains a PPFAC that will allow TEP to recover its actual cost of fuel and purchased power no matter what it turns out to be,

[5] The actual total increase as set forth in Exhibit WAR-1 is 21.15%. This testimony is explained in further detail below.

the differences between the two base costs of fuel and purchased power artificially and misleadingly lead one to believe that the Settlement Agreement is $38 million less than it actually is when compared to the Company and RUCO's original position.

Q. Have you prepared an Exhibit that restates the fallacies you have just described (i.e. the assumption that the fixed CTC is a permanent part of rates that has not already expired and the artificially low base cost of fuel and purchased power)?

A. Yes. I have prepared Exhibit WAR-1 that restates the fallacies just described and presents an accurate, as well as, apples-to-apples comparison of the Company, RUCO, and Staff original positions relative to the revenue requirement position contained in the Settlement Agreement.

Q. Please discuss how the parties positions compare to the Settlement once restated and demystified on Exhibit WAR-1.

A. In summary the parties' positions compare with the Settlement Agreement as follows:

| | Company As Filed | ACC Staff As Filed | RUCO As Filed | Settlement Agreement |
|---|---|---|---|---|
| Required Increase | $ 275,808,513 | $ 48,001,098 | $ 36,254,000 | $ 146,248,098 |
| Percentage Increase (excluding fixed CTC) | 39.89% | 6.94% | 5.24% | 21.15% |

The details supporting this restatement of the actual terms of the Settlement Agreement are set forth in Exhibit WAR-1. This apples-to-apples comparison clearly shows that the Settlement results in a far greater rate increase than portrayed by the Settling Parties, and in fact is a 21.15% increase, not a 6% increase. This result is hardly "fair, reasonable, and in the public interest", as portrayed by the Settling Parties.

Q. It appears that the rate increase recommended by the Settlement Agreement represents an amount almost $100 million greater than originally recommended by Staff. Does the Settlement document or any of the Settlement testimony attempt to explain this wide disparity?

A. Yes and no. Provided as Exhibit No. 2 of the Settlement Agreement is a dollar for dollar reconciliation of the concessions agreed to in the Settlement Agreement and such a reconciliation is also provided as Attachment RCS-7 to the Direct Testimony of Staff witness Ralph C. Smith. These two Exhibits identify each dollar disparity between the TEP and Staff direct testimony and the Settlement Agreement by issue. However, none of the documents explain the logic behind the Settlement concessions and why this additional $100 million rate increase is fair, reasonable, and in the public interest.

**DISCUSSION OF THE CONCESSIONS MADE IN THE SETTLEMENT AGREEMENT**

Q. Would you please discuss the more material items that comprise the $100 million in Settlement concessions?

A. Yes. Below I will discuss each of the larger concessions identified on Settlement Exhibit 2, pages 1 through 5.

The largest rate base concession identified on Settlement Exhibit 2 is the reinstatement of $99 million related to a FAS 143 write-off of accumulated depreciation. Staff had originally increased the accumulated depreciation balance by this write-off. RUCO also has a similar adjustment to increase the accumulated depreciation balance by $112.8 million related to this same FAS 143 issue.

Q. Why has this $99 million rate base concession been made as part of the Settlement Agreement?

A. According to Settlement Exhibit 2, page 1, this concession was made "For purposes of settlement."

...

Q. Didn't both the Staff and RUCO make compelling arguments in their respective direct testimonies regarding the appropriateness of this adjustment?

A. Yes. The Staff arguments are presented in the Direct Testimony of Ralph C. Smith, pages 31 through 34 and RUCO's arguments presented in the Direct Testimony of Marylee Diaz Cortez at pages 13 – 16. In summary original arguments in support of this adjustment were as follows:

Utilities have historically recognized the cost of asset retirement through annual depreciation accruals. These retirement costs, prior to Statement No. 143, resided in TEP's Accumulated Depreciation account, which under the ratemaking formula serves to reduce rate base. The account serves as a rate base reduction because it represents the portion of TEP's plant investment that it has already recovered through its depreciation accruals. Depreciation accruals (expenses) are included in the ratemaking formula, thus, by definition the Accumulated Depreciation account is comprised of amounts paid for by ratepayers. As just mentioned this account reduces rate base, thereby ensuring that ratepayers do not continue to pay a return on that portion of TEP's rate base investment for which ratepayers have already provided reimbursement. Statement No. 143, however, has upset the equity of depreciation accounting because it requires TEP to write-off a portion of the accumulated depreciation balance that ratepayers have already paid for. This write-off decreases the Accumulated Depreciation balance, which in turn increases rate base. The overall result of this accounting is that ratepayers will have to pay a return on portions of the Company's plant investment that ratepayers have already paid for through their utility rates. Thus, while Statement No. 143 may be appropriate from a financial accounting standpoint it is inappropriate for regulatory accounting. Financial and regulatory accounting have two entirely different objectives and thus often by necessity result in two sets of accounting. In this instance, application of the financial accounting for FAS 143 has unintended consequences when used for regulatory accounting purposes. In this case, if FAS 143 is recognized for ratemaking purposes the result will be double recovery of the previously accrued asset retirement costs.

Q. Please discuss the next material concession shown on Settlement Exhibit 2.

A. The next material rate base concession is for $41.6 million and is also related to accumulated depreciation. In 2004 TEP began recording depreciation expense on its generation assets at rates that were significantly lower than those that had been authorized by the Commission. As a result the accumulated depreciation reserve on the Company's books and records was significantly understated. Both Staff and RUCO in their direct testimonies made an adjustment to increase the accumulated depreciation balance to reflect the depreciation rates that had been authorized by the Commission.

Q. Where can Staff and RUCO's entire arguments on this issue be found?

A. Staff's arguments can be found in the direct testimony of Ralph C. Smith at pages 34 through 42 and RUCO's arguments in the direct testimony of Marylee Diaz Cortez at pages 5 through 8.

Q. Why have the Settling Parties conceded this point?

A. Settlement Exhibit 2 explains this $41.6 million concession as "For purpose of settlement and to be reflected in rates in this proceeding TEP's original position was accepted."

Q. Please discuss the next significant revenue requirement concession of the Settlement Agreement.

A. Settlement Exhibit 2 shows a concession to increase operating expenses by $29 million related to Springerville Unit 1. The Settling Parties have now agreed to include the Springerville Unit 1 lease in operating expense at an estimated market price of $25.67 per kilowatt-month fixed cost.

Q. What had been the parties' original positions on this issue?

A. The ACC Staff position was that Springerville Unit 1 should be included in rates a $15 per kilowatt-month fixed cost, which was consistent with the amount authorized in Decision No. 56659. A full discussion of the Staff's position can be found in the direct testimony of Ralph C. Smith at pages 49 through 52. RUCO's position on this issue was that Springerville Unit 1 should be included in rates at its embedded cost. A full discussion of RUCO's position is included in the direct testimony of Marylee Diaz Cortez at pages 8 through 10.

Q. Why have the settling parties now agreed to the much higher estimated market price of $25.67 per kilowatt-month?

A. Settlement Exhibit 2 explains this $41.6 million concession as "For purpose of settlement and to be reflected in rates the parties agree to adjustments that reflect the cost based recovery of Springerville Unit 1 non-fuel cost."

Q. Do you agree with the accuracy of this statement?

A. No. The $29 million concession would more accurately be described as allowing for adjustments that reflect the **estimated current market based cost** recovery of Springerville Unit 1 non-fuel cost. Obviously there is a vast difference between agreeing to cost based rates in a cost of service regulatory model (which is the model being adopted by the Settlement Agreement) and agreeing to estimated market-based rates in a cost of service model.

…

Q. Please discuss the next significant concession in the Settlement Agreement.

A. Settlement Exhibit shows that the parties have agreed to a $21.6 million increase in operating expenses for additional depreciation rates. The Settlement's $21.6 million increase in depreciation expenses is in fact $21.6 million in excess of what TEP had originally requested in its application.

Q. What explanation is given on Settlement Exhibit 2 for this $21.6 million in depreciation expenses beyond what the Company had even requested?

A. Settlement Exhibit 2 explains the $21.6 million increase as "For purpose of settlement and to be reflected in rates the parties agree on an adjustment of generation depreciation rates for the inclusion of $21.6 million (ACC Jurisdictional) in additional depreciation expense annually to recover cost of removal prospectively."

Q. Did any party in their direct testimony advocate the need for $21.6 million in additional depreciation for generation cost of removal?

A. No. No party advocated such a position, including TEP itself.

...

Q. Are there any other concessions made on particular issues in the context of the Settlement Agreement?

A. Yes. However the remaining concessions are far less significant than those already discussed. RUCO believes the original positions on these remaining concessions are clearly presented in the Settling Parties direct testimony and reading of those coupled with a comparison to the Settlement Agreement resolution of those same issues is self-explanatory.

Q. What is total revenue requirement impact of the above-discussed large concessions?

A. The revenue requirement of just the discussed concessions is as follows:

| | Revenue Req. Impact[6] |
|---|---|
| Rate Base Items | |
| FAS 143 Write-off | $13,296,484 |
| Unauthorized Depreciation Changes | 5,537,314 |
| | |
| Operating Expenses | |
| Springerville Unit 1 | 44,268,529 |
| Generation Depreciation Rates | 20,050,384 |
| | |
| Total | $83,152,771 |

...

[6] Revenue Requirement Impacts are per the Direct Settlement Testimony of Ralph C. Smith at page 6.

Q. Given the large and unexplained (or inadequately explained) discrepancies between the parties original positions and the settlement position is it possible to reach a conclusion the Settlement Agreement revenue requirement is fair, reasonable, and in the public interest?

A. No.

**OTHER SETTLEMENT AGREEMENT ISSUES**

Q. Are there any other aspects of the Settlement agreement you would like to address beside the just discussed revenue requirement?

A. Yes. There are a few other items I would like to discuss.

Q. What is the first additional issue you would like to discuss?

A. The Settlement Agreement provides for a PPFAC for TEP that is in large part patterned after that which was authorized for APS. Because of the overall make-up of TEP's generation, which is largely coal, RUCO does not believe a mechanism that is as broad based as that authorized for APS, which has a significant portion of its generation derived from gas, is warranted for TEP. RUCO recommended in its direct testimony[7] adoption of a limited PPFAC that was applicable only to incremental sales.

...

[7] See the Direct Testimony of Marylee Diaz Cortez at pages 26 through 32.

Q. What other flaws does RUCO see in the PPFAC proposed under the Settlement Agreement?

A. APS' fuel and power supply adjustor calls for a 90/10 sharing between ratepayers and shareholders of fuel and purchased power costs in excess of the base rate cost. This provision is intended to incent the Company to use prudent procurement practices. The PPFAC proposed for TEP would not have such a safeguard and as a result is deficient.

Q. Please discuss RUCO's second issue.

A. The Settlement Agreement specifically leaves open two issues of significant importance. These two issues are the 1) how the fixed CTC revenues that have been collected in excess of the $450 million authorized in Decision No. 62103 should be calculated and treated for ratemaking purposes, and 2) on what date any rate increase authorized in this docket should become effective.

Q. How significant are these two issues?

A. Very significant. On the first issue, Staff witness Ralph C. Smith testifies that the over collected CTC revenues will total approximately $68 million by the end of 2008. On the second issue, if the Settlement Agreement revenue increase of $136.8 million is adopted, this will generate monthly additional revenue of approximately $11.4 million, making the date on which the increase becomes effective highly significant.

Q. Can the fairness and the reasonableness of the Settlement Agreement be determined with these two issues outstanding?

A. No. These two issues have a potential impact of almost $100 million. Further, the Settling Parties have taken widely disparate positions on these two issues in their direct Settlement testimonies. It is difficult to image how a determination of the fairness and the reasonableness of the Settlement Agreement was reached by the Parties when two issues of this significance remain outstanding.

Q. Please address RUCO's third issue.

A. The Settlement Agreement leaves open the question of whether or not TEP's service territory is eligible for retail competition. While paragraph 14.1 of the Agreement recognizes that "the transition to retail electric competition has thus far not occurred and the time periods applicable to Decision No. 62103 and to the 1999 Settlement Agreement have passed, the Signatories recognize that it is necessary to address the prospective regulatory treatment that is appropriate for TEP under these circumstances.", the Settlement Agreement defers this important issue to a later generic docket. Since 2002, RUCO has consistently taken the position that retail competition is not in the best interests of residential ratepayers and that even if it were the possible benefits to residential ratepayers, if any, are far outweighed by the risks. The Settlement's deferral of this important issue is yet another deficit in the Agreement.

Q. Does this conclude your responsive direct Settlement Agreement Testimony?

A. Yes.

RUCO'S EXHIBIT WAR-1

**TUCSON ELECTRIC POWER COMPANY**
**PROPOSED SETTLEMENT AGREEMENT**
**COMPARISON TO AS FILED POSITIONS**

**DOCKET NO. E-01933A-07-0402**
**DOCKET NO. E-01933A-05-0650**
**EXHIBIT WAR-1**

| LINE NO. | DESCRIPTION | COMPANY AS FILED | ACC STAFF AS FILED | RUCO | SETTLEMENT AGREEMENT |
|---|---|---|---|---|---|
| 1 | REQUIRED REVENUE INCREASE | $158,186,000 | 9,753,000 | 36,254,000 | 136,800,000 |
| 2 | TCRAC | 117,622,513 | 0 | 0 | 0 |
| 3 | FUEL COST CONVERSION | 0 (a) | 38,248,098 (b) | 0 (a) | 38,248,098 (b) |
| 4 | SUBTOTAL | 275,808,513 | 48,001,098 | 36,254,000 | 175,048,098 |
| 5 | CREDITS TO PPFAC | 0 | 0 | 0 | (28,800,000) (C) |
| 6 | TOTAL | 275,808,513 | 48,001,098 | 36,254,000 | 146,248,098 |
| 7 | PERCENTAGE INCREASE | 39.89% | 6.94% | 5.24% | 21.15% (d) |

(a) TEP BASE COST OF FUEL =
$307,525,562/9,318,849,104 = .033

(b) STAFF BASE COST OF FUEL =
$269,276,010/9,318,849,104 = .028896
INCREMENTAL DIFFERENCE =
.033 -.028896 = .00410438 x 9,318,849,104 = $38,248,098

(C) SHORT TERM SALES $25,300,000
SO2 ALLOWANCE $3,300,000
10% OF WHOLESALE REVENUE $200,000

(d) ADJUSTED CURRENT REVENUES EXCLUDING CTC =
$691,372,378

**BEFORE THE ARIZONA CORPORATION COMMISSION**

MIKE GLEASON
CHAIRMAN
WILLIAM A. MUNDELL
COMMISSIONER
JEFF HATCH-MILLER
COMMISSIONER
KRISTIN K. MAYES
COMMISSIONER
GARY PIERCE
COMMISSIONER

**RECEIVED**

JUL 07 2008

Lawrence V. Robertson, Jr.

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA | Docket No. E-01933A-07-0402 |
| IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103. | Docket No. E-01933A-05-0650 |

**NOTICE OF ERRATA**

The Residential Utility Consumer Office ("RUCO") hereby files this Notice of Errata to correct the cover page of the testimony of William A. Rigsby, in the above-referenced matter. Please substitute the attached cover page on the testimony filed on July 2, 2008.

RESPECTFULLY SUBMITTED this 3rd day of July 2008

Daniel W. Pozefsky
Chief Counsel

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of July 2008 with:

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By Ernestine Gamble
Ernestine Gamble
Secretary to Daniel Pozefsky

RUCO2

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

# RESPONSIVE DIRECT SETTLEMENT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 2, 2008

RU EXHIBIT
3
admitted

# 1.
# Value Line Ranks

| | | |
|---|---|---|
| TIMELINESS | 2 | Raised 10/27/06 |
| SAFETY | 1 | New 7/27/90 |
| TECHNICAL | 2 | Raised 11/10/06 |
| BETA .70 (1.00 = Market) | | |

Ranks Box

***Timeliness***

The Timeliness rank is Value Line's measure of the expected price performance of a stock for the coming six to 12 months relative to our approximately 1,700 stock universe. Stocks ranked 1 (Highest) and 2 (Above Average) are likely to perform best relative to the approximately 1,700 stocks we follow. Stocks ranked 3 are likely to be average performers. Stocks ranked 4 (Below Average) and 5 (Lowest) are likely to underperform stocks ranked 1 through 3 in Value Line's universe.

At any one time, there are 100 stocks ranked 1; 300 ranked 2; approximately 900 ranked 3; 300 ranked 4; and 100 ranked 5.

Value Line has published Timeliness ranks for more than 33 years. Twice a year, in January and July, the results of the performance of the Timeliness ranks are published in Selection & Opinion. Overall, the results have been truly outstanding. Mark Hulbert, a *Forbes* columnist who studies the performance of investment publications, has written that over a 17-year period, *The Value Line Investment Survey* "...is in first place for risk adjusted performance."

The most important factor in determining the Timeliness rank is earnings growth. Companies whose earnings growth over the past 10 years has been greater than their stocks' price appreciation tend to have high scores. In addition, the ranks take into account a stock's recent price performance relative to all approximately 1,700 stocks in the Value Line universe. A company's recent quarterly earnings performance and any recent earnings surprises caused because a company reported results that were significantly better or worse than expected are also factors. They are combined to determine the Timeliness rank.

Just one word of caution. Stocks ranked 1 for Timeliness are often more volatile than the overall market and tend to have smaller capitalizations (the total value of a company's outstanding shares, calculated by multiplying the number of shares outstanding by the stock's price per share). Conservative investors may want to select stocks that also have high Safety ranks because they are more stable issues.

***Industry***

Value Line also publishes Industry ranks which show the Timeliness of each industry. The Industry ranks indicate how Value Line believes the prices of stocks within 90 or more industries will perform relative to each other. These ranks are updated weekly and published on the front cover and inside the Summary & Index. They also appear at the top of each Industry Report in Ratings & Reports. The Industry rank is calculated by averaging the Timeliness ranks of each of the stocks assigned a Timeliness rank in a particular industry.

***Safety***

| | |
|---|---|
| Company's Financial Strength | A++ |
| Stock's Price Stability | 85 |
| Price Growth Persistence | 100 |
| Earnings Predictability | 100 |

Financial/Stock Price Data

The Safety rank is a measure of the total risk of a stock compared to others in our approximately 1,700 stock universe. As with Timeliness, Value Line ranks each stock from 1 (Highest) to 5 (Lowest). However, unlike Timeliness, the number of stocks in each category from 1 to 5 may vary. The Safety rank is derived from two measurements (weighted equally) found in the lower right hand corner of each page: a Company's Financial Strength and a Stock's Price Stability. Financial Strength is a measure of the company's financial condition, and is reported on a scale of A++ (highest) to C (lowest). The largest companies with the strongest balance sheets get the highest scores. Price Stability is based on a ranking of the standard deviation (a measure of volatility) of weekly percent changes in the price of a company's own stock over the last five years, and is reported on a scale of 100 (highest) to 5 (lowest) in increments of 5. Generally speaking, stocks with Safety ranks of 1 and 2 are most suitable for conservative investors. A stock's Price Growth Persistence and a company's Earnings predictability are also included in the box above, but do not factor into the Safety rank. However, they are useful statistics.

***Technical***

The Technical rank is primarily a predictor of a stock's short term (three to six months) relative price change. It is based on a proprietary model which examines 10 relative price trends for a particular stock over different periods in the past year. It also takes into account the price volatility of each stock. The Technical ranks also range from 1 (Highest) to 5 (Lowest). At any one time, about 100 stocks are ranked 1; 300 ranked 2; 900 ranked 3; 300 ranked 4; and 100 ranked 5.

***Beta***

Beta is a measure of volatility and is calculated by Value Line. While it is not a rank, we do consider it important.

# UNISOURCE ENERGY NYSE-UNS

| RECENT PRICE | P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD |
|---|---|---|---|
| 31.80 | 18.9 (Trailing: 20.5 / Median: 17.0) | 1.14 | 3.0% |

VALUE LINE

TIMELINESS 4 Raised 8/17/07
SAFETY 3 New 12/31/04
TECHNICAL 3 Lowered 4/25/08
BETA .60 (1.00 = Market)

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 18.3 | 18.9 | 13.9 | 19.3 | 26.0 | 20.8 | 24.9 | 24.9 | 34.8 | 37.5 | 40.0 | 33.5 | | |
| Low: | 13.9 | 12.3 | 10.4 | 11.1 | 13.8 | 13.7 | 16.0 | 22.9 | 24.3 | 29.5 | 27.6 | 21.3 | | |

Target Price Range
2011 | 2012 | 2013

**2011-13 PROJECTIONS**

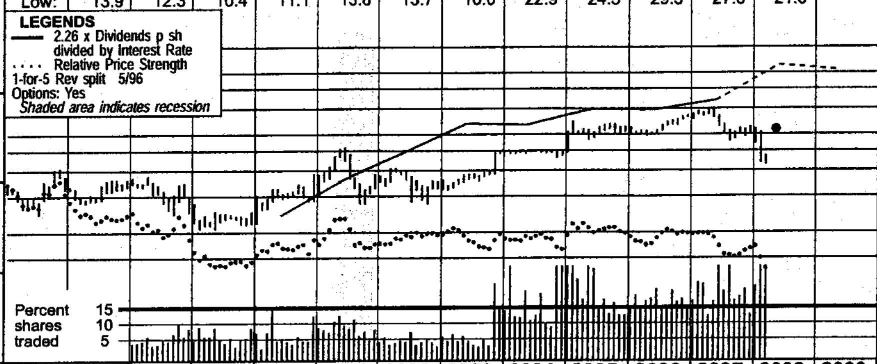
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 35 | (+10%) | 6% |
| Low | 20 | (-35%) | -6% |

**Insider Decisions**

| | J | J | A | S | O | N | D | J | F |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 1 | 0 | 0 | 2 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 |

**Institutional Decisions**

| | 2Q2007 | 3Q2007 | 4Q2007 |
|---|---|---|---|
| to Buy | 73 | 56 | 73 |
| to Sell | 81 | 87 | 59 |
| Hld's(000) | 30634 | 31880 | 33110 |




% TOT. RETURN 3/08

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -38.8 | -11.0 |
| 3 yr. | -22.0 | 18.2 |
| 5 yr. | 47.3 | 109.5 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19.56 | 20.61 | 21.51 | 20.87 | 22.28 | 22.71 | 23.83 | 24.85 | 31.12 | 43.12 | 25.50 | 28.71 | 34.13 | 35.26 | 37.42 | 39.12 | *41.20* | *43.35* | Revenues per sh | *49.60* |
| d.30 | 2.06 | 3.44 | 4.58 | 6.82 | 5.29 | 3.48 | 3.96 | 4.23 | 5.41 | 4.80 | 5.20 | 5.29 | 5.21 | 5.68 | 5.64 | *6.15* | *6.70* | "Cash Flow" per sh | *8.25* |
| d12.40 | d.25 | .65 | 1.70 | 3.76 | 2.60 | .68 | 1.08 | 1.27 | 1.79 | .97 | 1.30 | 1.31 | 1.30 | 1.85 | 1.55 | *1.65* | *1.75* | Earnings per sh A | *1.90* |
| -- | -- | -- | -- | -- | -- | -- | -- | .32 | .40 | .50 | .60 | .64 | .76 | .84 | .90 | *.96* | *1.02* | Div'd Decl'd per sh B ■ † | *1.20* |
| 1.08 | 1.50 | 1.95 | 1.84 | 2.07 | 2.22 | 2.52 | 2.87 | 3.19 | 3.63 | 3.36 | 4.06 | 4.49 | 5.83 | 6.77 | 6.95 | *8.60* | *6.90* | Cap'l Spending per sh | *5.90* |
| d1.19 | d1.96 | d1.31 | .39 | 4.15 | 6.75 | 7.65 | 10.02 | 11.20 | 12.68 | 13.05 | 15.97 | 16.95 | 17.68 | 18.59 | 19.54 | *20.40* | *21.20* | Book Value per sh C | *23.65* |
| 32.09 | 32.14 | 32.14 | 32.13 | 32.13 | 32.14 | 32.26 | 32.35 | 33.22 | 33.50 | 33.58 | 33.79 | 34.26 | 34.87 | 35.19 | 35.32 | *35.70* | *36.20* | Common Shs Outst'g D | *37.70* |
| -- | -- | 26.7 | 9.6 | 4.3 | 6.1 | 23.3 | 10.8 | 11.8 | 10.8 | 18.2 | 14.6 | 18.7 | 23.9 | 17.7 | 22.0 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.5* |
| -- | -- | 1.75 | .64 | .27 | .35 | 1.21 | .62 | .77 | .55 | .99 | .83 | .99 | 1.27 | .96 | 1.16 | *Value Line* | | Relative P/E Ratio | *.95* |
| -- | -- | -- | -- | -- | -- | -- | -- | 2.1% | 2.1% | 2.8% | 3.2% | 2.6% | 2.5% | 2.6% | 2.6% | *estimates* | | Avg Ann'l Div'd Yield | *4.3%* |

**CAPITAL STRUCTURE as of 12/31/07**
**Total Debt $1797.7 mill. Due in 5 Yrs $1025.3 mill.**
**LT Debt $1524.8 mill. LT Interest $137.5 mill.**
Incl. $531.1 mill. capitalized leases.

(LT interest earned: 1.7x)

**Pension Assets-12/07** $193 mill. **Oblig.** $209 mill.
**Pfd Stock** None

**Common Stock** 35,315,000 shs.
**MARKET CAP: $1.1 billion (Mid Cap)**

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 768.7 | 803.8 | 1033.7 | 1444.7 | 856.2 | 969.9 | 1169.0 | 1229.5 | 1316.9 | 1381.4 | *1470* | *1570* | Revenues ($mill) | *1870* |
| 21.9 | 35.5 | 26.3 | 60.9 | 33.3 | 45.2 | 45.9 | 46.1 | 69.2 | 58.4 | *59.0* | *63.0* | Net Profit ($mill) | *72.0* |
| 45.6% | 46.8% | 32.9% | 43.8% | 33.7% | 19.7% | 42.5% | 41.4% | 38.8% | 40.1% | *40.0%* | *40.0%* | Income Tax Rate | *40.0%* |
| -- | -- | -- | -- | -- | 2.2% | -- | -- | 2.9% | 3.4% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| 89.4% | 86.1% | 84.2% | 79.6% | 81.5% | 79.2% | 77.1% | 75.3% | 72.9% | 68.8% | *67.5%* | *66.0%* | Long-Term Debt Ratio | *61.0%* |
| 10.6% | 13.9% | 15.8% | 20.4% | 18.5% | 20.8% | 22.9% | 24.7% | 27.1% | 31.2% | *32.5%* | *34.0%* | Common Equity Ratio | *39.0%* |
| 2320.6 | 2340.5 | 2362.4 | 2081.3 | 2368.8 | 2589.0 | 2540.3 | 2494.9 | 2414.1 | 2214.9 | *2230* | *2245* | Total Capital ($mill) | *2290* |
| 1915.6 | 1729.9 | 1706.3 | 1677.7 | 1668.4 | 2069.2 | 2081.1 | 2171.5 | 2259.6 | 2407.3 | *2555* | *2625* | Net Plant ($mill) | *2765* |
| 2.5% | 2.9% | 2.5% | 4.4% | 2.8% | 4.9% | 5.1% | 5.1% | 5.9% | 5.7% | *5.5%* | *6.0%* | Return on Total Cap'l | *6.0%* |
| 8.9% | 11.0% | 7.1% | 14.3% | 7.6% | 8.4% | 7.9% | 7.5% | 10.6% | 8.5% | *8.0%* | *8.5%* | Return on Shr. Equity | *8.0%* |
| 8.9% | 11.0% | 7.1% | 14.3% | 7.6% | 8.4% | 7.9% | 7.5% | 10.6% | 8.5% | *8.0%* | *8.5%* | Return on Com Equity E | *8.0%* |
| 8.9% | 11.0% | 4.3% | 11.2% | 3.8% | 4.6% | 4.1% | 3.2% | 6.1% | 3.9% | *3.5%* | *3.5%* | Retained to Com Eq | *3.0%* |
| -- | -- | 39% | 22% | 51% | 45% | 48% | 57% | 43% | 54% | *58%* | *58%* | All Div'ds to Net Prof | *63%* |

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.9 | +3.7 | +4.7 |
| Avg. Indust. Use (MWH) | 3421 | 3431 | 3652 |
| Avg. Indust. Revs. per KWH (¢) | 6.60 | 6.60 | 6.60 |
| Capacity at Peak (Mw) | 2567 | 2696 | 3064 |
| Peak Load, Summer (Mw) | 2792 | 2913 | 2984 |
| Annual Load Factor (%) | 63.9 | 64.0 | 64.1 |
| % Change Customers (yr-end) | +2.6 | +1.8 | +1.2 |
| Fixed Charge Cov. (%) | 131 | 157 | 153 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 5.5% | 2.5% | *5.0%* |
| "Cash Flow" | -- | 2.5% | *7.0%* |
| Earnings | -5.5% | 3.0% | *3.0%* |
| Dividends | -- | 15.5% | *6.5%* |
| Book Value | 17.5% | 8.5% | *4.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 260.9 | 300.6 | 349.3 | 318.7 | 1229.5 |
| 2006 | 305.0 | 318.4 | 375.6 | 317.9 | 1316.9 |
| 2007 | 317.8 | 329.8 | 398.2 | 335.6 | 1381.4 |
| 2008 | *345* | *360* | *415* | *350* | *1470* |
| 2009 | *365* | *380* | *445* | *380* | *1570* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | d.11 | .27 | .49 | .65 | 1.30 |
| 2006 | .52 | .28 | .73 | .32 | 1.85 |
| 2007 | .14 | .32 | .66 | .43 | 1.55 |
| 2008 | *.20* | *.35* | *.70* | *.40* | *1.65* |
| 2009 | *.22* | *.37* | *.75* | *.41* | *1.75* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .16 | .16 | .16 | .16 | .64 |
| 2005 | .19 | .19 | .19 | .19 | .76 |
| 2006 | .21 | .21 | .21 | .21 | .84 |
| 2007 | .225 | .225 | .225 | .225 | .90 |
| 2008 | .24 | | | | |

**BUSINESS:** UniSource Energy Corp., parent of Tucson Electric Power Company, supplies electricity in Tucson, Arizona and the surrounding area (serv. area: 1,155 sq. miles). Nonutility subsidiaries engage in plant construction, fuel supply, and related businesses. Revenue sources: residential, 45%; commercial, 26%; industrial, 21%; other, 8%. Copper mining is largest industry served. Fuels: coal, 92%; gas, 8%. Fuel: 49% of electric revenues; labor costs: 9%. '07 depreciation rate: 3.4%. Estimated plant age: 10 years. Has 1,306 employees. Chairman, President, and Chief Executive Officer: James S. Pignatelli. Inc.: AZ. Address: One South Church Ave. Suite 1820, Tucson, AZ 85701. Tel.: 520-884-3650. Internet: www.unisourceenergy.com.

**UniSource expects a decision by yearend on its request for higher electric rates.** In 1999, the company's Tucson Electric Power subsidiary's rates were frozen through 2008. To offset the earnings deficiency during that period resulting from higher unrecovered costs, UNS asked regulators for an increase of $172 million. It proposed that one of three alternatives be used in setting new rates. In each instance, transmission and distribution tariffs would be based on historic cost-based calculations. But generation rates would be figured differently. Power charges would either be based on wholesale market prices, less profitable cost of service plus an additional fee, or a conbination of the two. The first two options would lead to increases of about 22%. The third would generate slightly lesser rates. A commission decision on the filing is expected by yearend.

**The company is investing in new transmission lines.** The Arizona commission staff has stated that the state has insufficient transmission to accommodate new plants. Acting on this information, UNS and partners are stringing a 500-kilovolt line to provide additional access to energy resources in the Palo Verde market. Completion is targeted for midyear. Two more projects are under development. One is a 62-mile line from Tucson to Nogales, Arizona to improve reliability in that region. The other is expansion of a link with the Phoenix area to enhance the flow of power throughout the state. Construction of this line will take two years.

**Earnings should improve in 2008.** Pluses include higher gas rates of $5 million and the absence of last year's plant outages that increased fuel and purchased power costs and limited sales opportunities. Though interest expense will be higher due to new transmission, we estimate 2008 earnings will rise 6%, to $1.65 a share. An order on the pending rate case points to a further gain next year. The stock is untimely.

**These shares might interest income-oriented investors.** Dividend growth prospects to 2011-2013 are well above the utility norm. But UniSource's weak finances might deter those of a conservative bent.

*Arthur H. Medalie* *May 9, 2008*

(A) EPS diluted. Next earnings report due late May. Excl. nonrecur. gains (losses): '92, 18¢; '93, ($0.11); '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '07: $3.47/sh. (D) In millions. (E) Rate base: fair value. Rate allowed on com. eq. in '94: 11.0%; earned on avg. com. eq., '07: 8.7%. Regulatory Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | C++ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 90 |
| Earnings Predictability | 40 |